**CLASS VI LOGGING AND TESTING**

**INJECTION WELL 357-7R**
**40 CFR 146.82(c)(4),(7) and 146.87(a)(1)-(3)**

**ELK HILLS A1-A2 PROJECT**

## <u>Injection Well 357-7R Logging and Testing</u>

The 357-7R injection well is being repurposed for the Elk Hills A1-A2 project. The 357-7R well has been approved by California Geologic Energy Management (CalGEM) for Class II pressure maintenance using gas as injectate.

### Deviation Checks During Drilling

Deviation checks for 357-7R were acquired during drilling every ten feet from 3,540.52 feet true vertical depth (TVD) to bottom hole at 8,995.93 feet TVD (Figure 1).

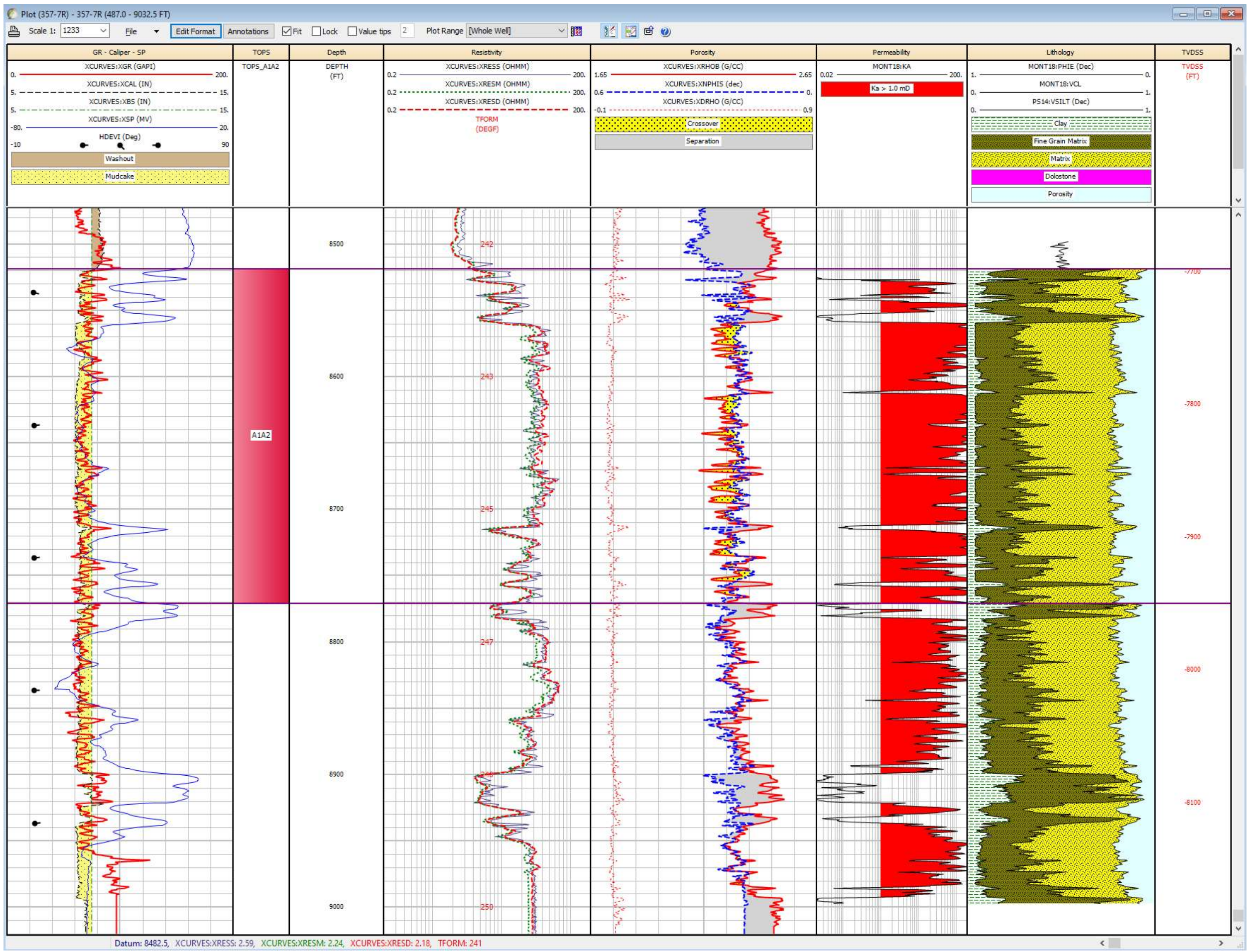
**Figure 1: Deviation checks during drilling for the 357-7R well.**

| X ftUS | Y ftUS | Z ft | MD ft | Inclination deg | Azimuth GN deg | Azimuth TN deg | DX ftUS | DY ftUS | DX TN ftUS | DY TN ftUS | TVD (Well datum) ft | TWT ms | DLS deg/100ft |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6100830.00 | 2309245.00 | 812.00 | 0.00 | 0.00 | 165.70 | 164.82 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | | 0.00 |
| 6100843.74 | 2309191.11 | -2728.52 | 3541.10 | 1.80 | 165.70 | 164.82 | 13.74 | -53.89 | 14.56 | -53.68 | 3540.52 | | 0.05 |
| 6100843.83 | 2309190.81 | -2738.51 | 3551.10 | 1.80 | 158.50 | 157.62 | 13.83 | -54.19 | 14.67 | -53.97 | 3550.51 | | 2.26 |
| 6100843.91 | 2309190.53 | -2748.51 | 3561.10 | 1.50 | 170.00 | 169.12 | 13.91 | -54.47 | 14.75 | -54.25 | 3560.51 | | 4.45 |
| 6100843.95 | 2309190.28 | -2758.51 | 3571.10 | 1.40 | 174.30 | 173.42 | 13.95 | -54.72 | 14.79 | -54.50 | 3570.51 | | 1.48 |
| 6100843.98 | 2309190.03 | -2768.40 | 3581.00 | 1.60 | 170.00 | 169.12 | 13.98 | -54.97 | 14.83 | -54.75 | 3580.40 | | 2.32 |
| 6100947.59 | 2308941.03 | -8136.56 | 8957.60 | 2.30 | 76.40 | 75.52 | 117.59 | -303.97 | 122.25 | -302.14 | 8948.56 | | 0.00 |
| 6100947.98 | 2308941.13 | -8146.45 | 8967.50 | 2.30 | 75.00 | 74.12 | 117.98 | -303.87 | 122.63 | -302.03 | 8958.45 | | 0.57 |
| 6100948.36 | 2308941.23 | -8156.45 | 8977.50 | 2.30 | 76.40 | 75.52 | 118.36 | -303.77 | 123.02 | -301.93 | 8968.45 | | 0.56 |
| 6100948.75 | 2308941.30 | -8166.44 | 8987.50 | 2.20 | 80.70 | 79.82 | 118.75 | -303.70 | 123.41 | -301.84 | 8978.44 | | 1.96 |
| 6100949.12 | 2308941.36 | -8176.43 | 8997.50 | 2.10 | 82.10 | 81.22 | 119.12 | -303.64 | 123.78 | -301.78 | 8988.43 | | 1.13 |
| 6100949.39 | 2308941.40 | -8183.93 | 9005.00 | 2.10 | 82.10 | 81.22 | 119.39 | -303.60 | 124.05 | -301.74 | 8995.93 | | 0.00 |

### 357-7R Open Hole Log Analysis: Before Installation of Long String

Open-hole wireline log data was acquired in 357-7R with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity, neutron porosity and bulk density (Figure 2).

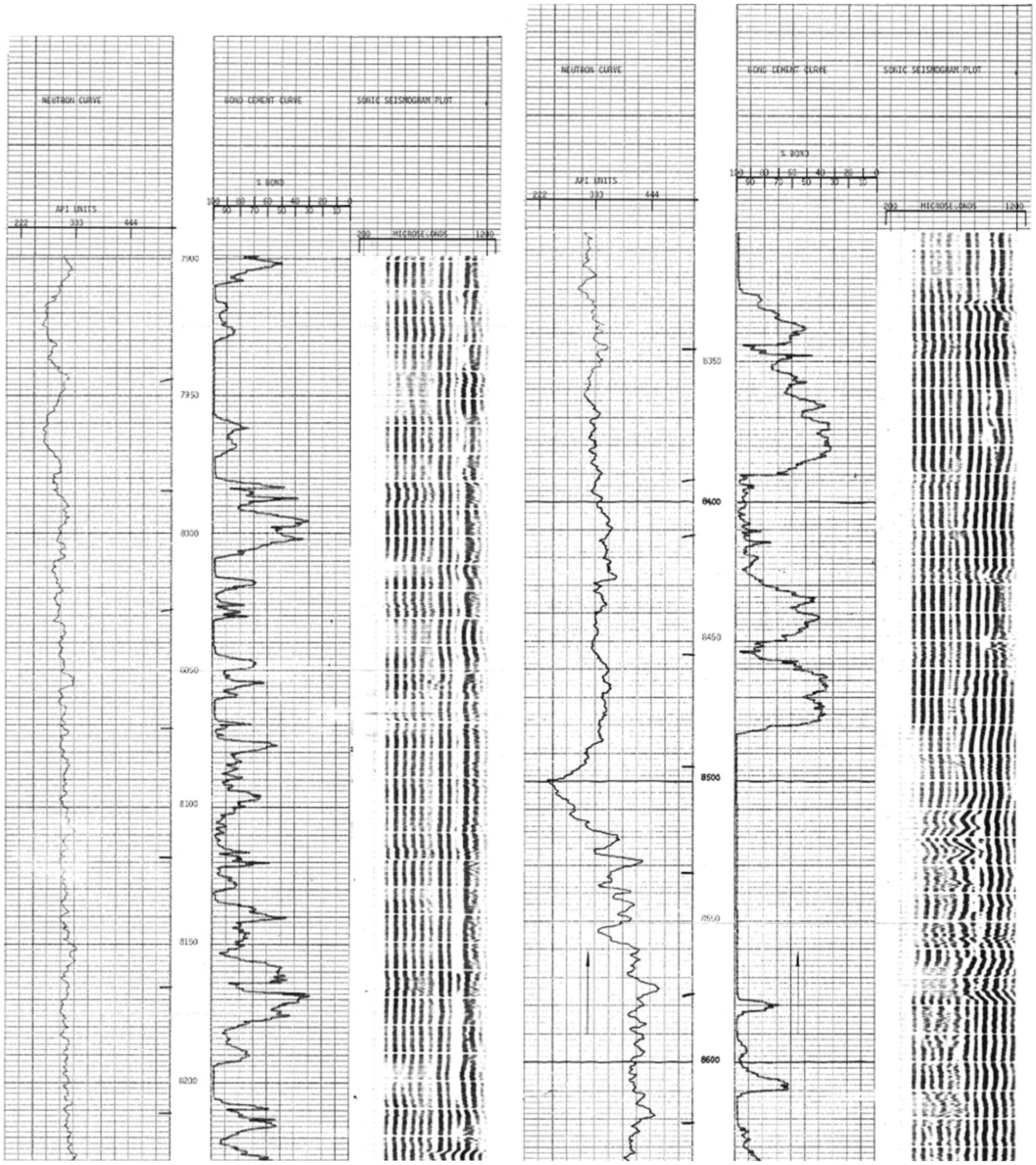
**Figure 2: Open-hole well logs for 357-7R before installation of long string.**



## 357-7R Cased Hole: After Installation of Long String

The cement bond log seismogram and percent bond show isolation between the injection zone and shallow formations. Late seismogram arrivals show the presence of cement throughout the interval and bond from cement to formation. Early, low amplitude seismogram signal shows bond between pipe and cement (Figure 3).

**Figure 3: Cement bond log example for 357-7R, after installation of long string casing. The Monterey Formation A1-A2 top is at 8,518 feet.**



# CLASS VI MECHANICAL INTEGRITY TESTING

# INJECTION WELL 357-7R
# 40 CFR 146.82(c)(7)-(8) and 146.87(a)(4)

# ELK HILLS A1-A2 PROJECT

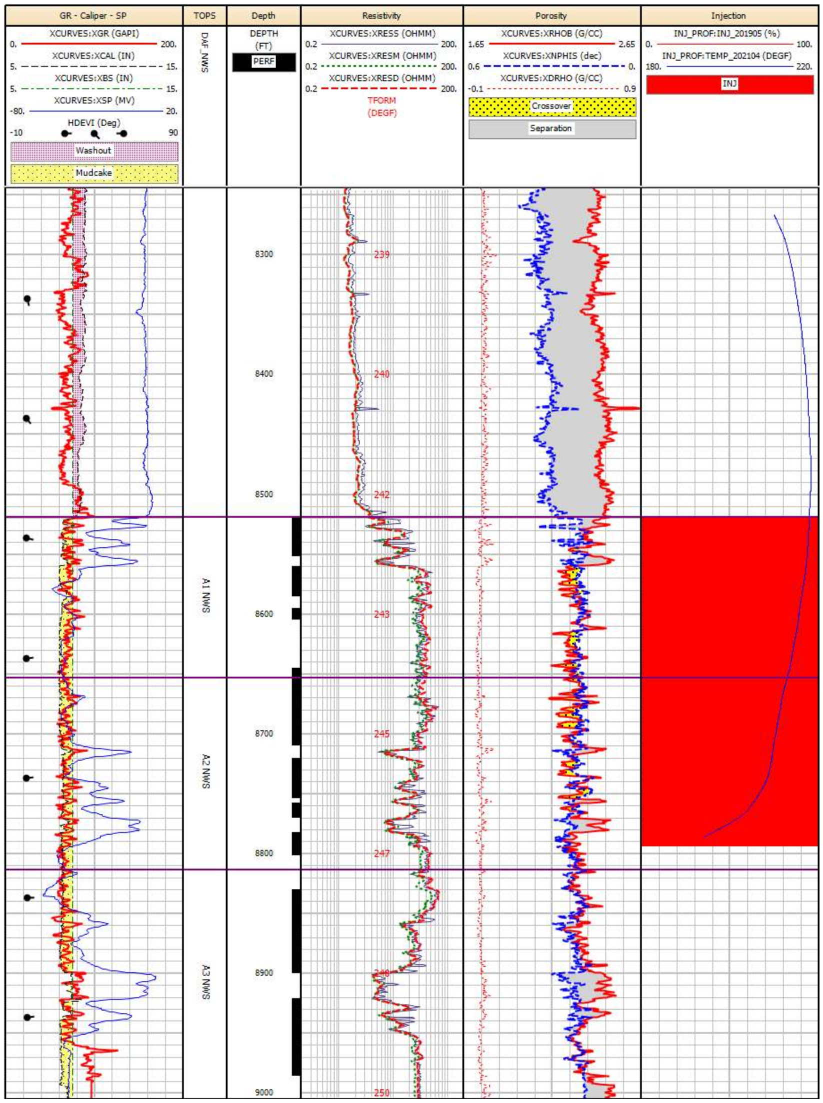
## 357-7R Mechanical Integrity Testing

The 357-7R and 355-7R injection wells are being repurposed for the Carbon TerraVault 1 LLC (CTV) Elk Hills A1-A2 project. These wells have been approved by California Geologic Energy Management (CalGEM) for Class II gas injection for pressure maintenance. As part of this approval and ongoing surveillance, mechanical integrity tests (MIT) and standard annular pressure tests (SAPT) have been conducted. CTV will acquire additional mechanical integrity tests prior to the injection of $CO_2$.

357-7R Gas Injection Survey

The gas injection survey (conducted in 2019) uses radioactive tracer to determine injection zone conformance. The interpreted log example below (Figure 1) shows 100% of the injection confined to 8520-8794 feet. The temperature curve shows that injection is confined below the packer as temperature trends toward gradient above the packer.

**Figure 1: Radioactive tracer and temperature survey for well 357-7R showing mechanical integrity of the tubing and isolation of the perforation by the packer.**



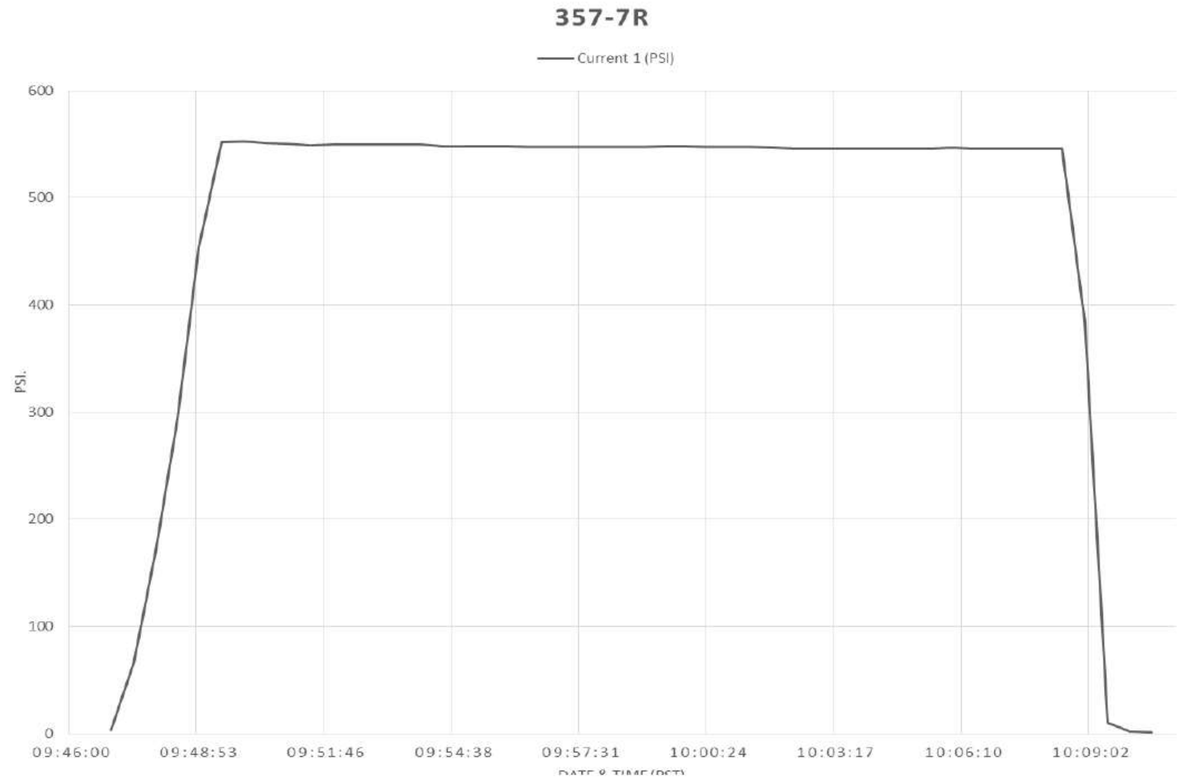

357-7R Standard Annular Pressure Testing

The standard annular pressure test (Figure 2) shows that the annulus is capable of holding pressure without gain or loss for 20 to 30 minutes indicating mechanical integrity of the tubing, casing and packer.

**Figure 2: SAPT for 357-7R showing mechanical integrity of the tubing, casing, and packer.**

# CRC SAPT TEST

| Well | 357 | DOGGR Rep | Donald James | Date: | 03/04/19 |
|---|---|---|---|---|---|
| Section | 7R | Witness/Waived | Waived | Time: | 9:52:00 AM |
| API# | 02962150 | Company Rep | Tony Shadden | Operator | Benito Garcia |



**CLASS VI INJECTION WELL TESTING**

**INJECTION WELL 357-7R**
**40 CFR 146.82(c)(4),(7) and 146.87(e)**

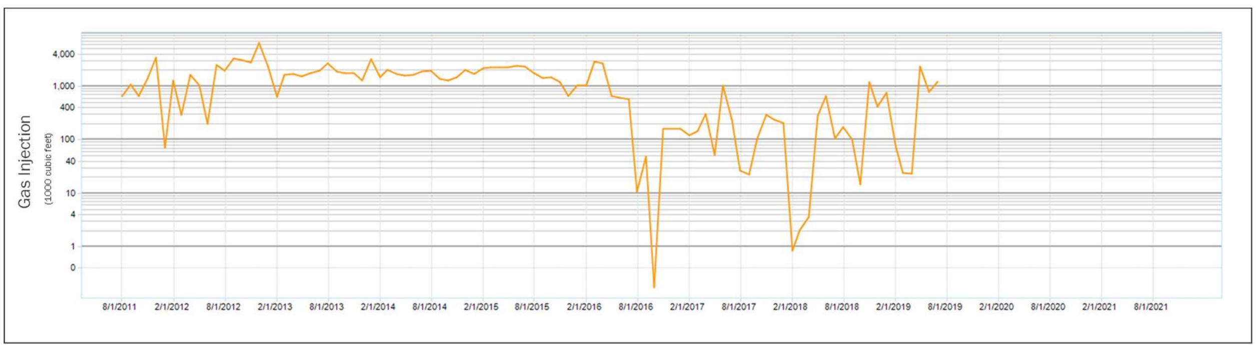
**ELK HILLS A1-A2 PROJECT**

## Well 357-7R Injection

The 357-7R injection well is being repurposed for the Elk Hills A1-A2 project. Injection was approved by California Geologic Energy Management (CalGEM) for Class II gas injection for pressure maintenance. Since 2011 3.5 billion cubic feet of gas has been injected in well 357-7R (Figure 1), with $CO_2$ composition as high as 44%. The maximum rate of injection for the 357-7R well since 2011 is 6.5 million cubic feet per day.

Gas injection for the purpose of supporting Monterey Formation A1-A2 reservoir pressure initiated in 1982. Cumulative gas injection is 175 billion cubic feet, with individual well injection rates as high as 30 million cubic feet per day.

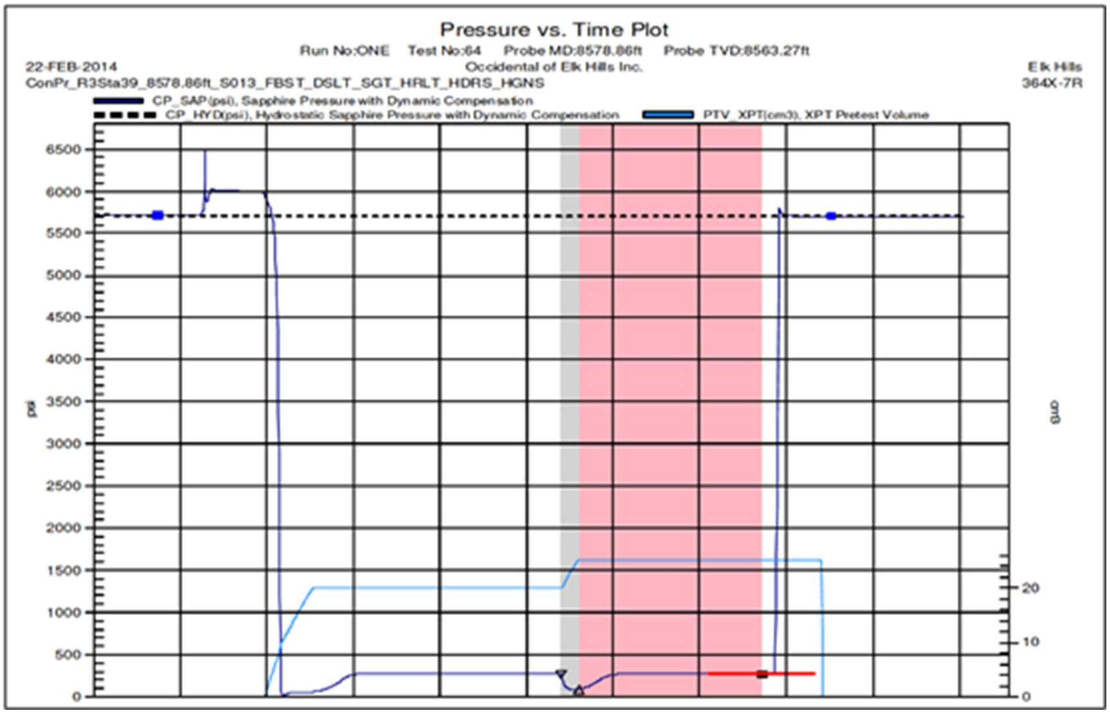
**Figure 1: 357-7R gas injection rate.**




Pressure Build-Up Test

Below (Figure 2) is an example build-up test from well 364X-7R taken at 8578.86 feet measured depth in the Monterey Formation A1-A2 reservoir.

**Figure 2: Pressure build-up test for the Monterey Formation A1-A2 reservoir in well 364X-7R.**


Pressure vs. Time Plot
Run No:ONE Test No:64 Probe MD:8578.86ft Probe TVD:8563.27ft
22-FEB-2014
Occidental of Elk Hills Inc.
Elk Hills
ConPr_R3Sta39_8578.86ft_S013_FBST_DSLT_SGT_HRLT_HDRS_HGNS
364X-7R
CP_SAP(psi), Sapphire Pressure with Dynamic Compensation
CP_HYD(psi), Hydrostatic Sapphire Pressure with Dynamic Compensation
PTV_XPT(cm3), XPT Pretest Volume
psi
cm3
6500
6000
5500
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
20
10
0

# ATTACHMENT G: CONSTRUCTION DETAILS
# WELL 357-7R

## Elk Hills A1-A2 Storage Project

### Facility Information

Facility name: Elk Hills A1-A2 Storage
357-7R

Facility contact: Kenneth Haney / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 763-6101/ Kenneth.Haney@crc.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

### Introduction

The testing activities at the 357-7R described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C, along with other non-well related pre-injection baseline activities such as geochemical monitoring.

Injection well 357-7R is an existing well approved for gas injection as part of a UIC approval for pressure maintenance. The well has cumulative injection of 3.5 billion cubic feet of gas. As part of the UIC approval, California Resources Corporation (CRC) has conducted annual MITs and SAPT tests every five years to ensure internal and external mechanical integrity.

## Injection Well Construction Details

### *Casing Specifications*

| Name | Depth Interval (feet) | Outside Diameter (inches) | Inside Diameter (inches) | Weight (lb/ft) | Grade (API) | Design Coupling (Short or Long Threaded) | Thermal Conductivity @ 77°F (BTU/ft hr, °F) | Burst Strength (psi) | Collapse Strength (psi) |
|---|---|---|---|---|---|---|---|---|---|
| Conductor | 20-60 | 20.000 | 19.5 | 52 | H-40 | Short | 31 | 875 | 90 |
| Surface | 20-501 | 13.375 | 12.715 | 48 | H-40 | Short | 31 | 1,727 | 740 |
| Intermediate | 20-3,517 | 9.625 | 8.835 | 40 | N-80 | Long | 31 | 5,750 | 3,090 |
| Long-string | 20-8,990 | 7.000 | 6.184<br>6.276<br>6.366 | 29<br>26<br>23 | N-80 | Long | 31 | 8,160<br>7,240<br>6,340 | 7,020<br>5,410<br>3,830 |

### *Tubing Specifications*

| Name | Depth Interval (feet) | Outside Diameter (inches) | Inside Diameter (inches) | Weight (lb/ft) | Grade (API) | Design Coupling (Short or Long Thread) | Burst strength (psi) | Collapse strength (psi) |
|---|---|---|---|---|---|---|---|---|
| Injection tubing | 8,454 | 4.500 | 3.826 | 15.2 | 13CR-95 | Long (premium) | 12,450 | 12,760 |

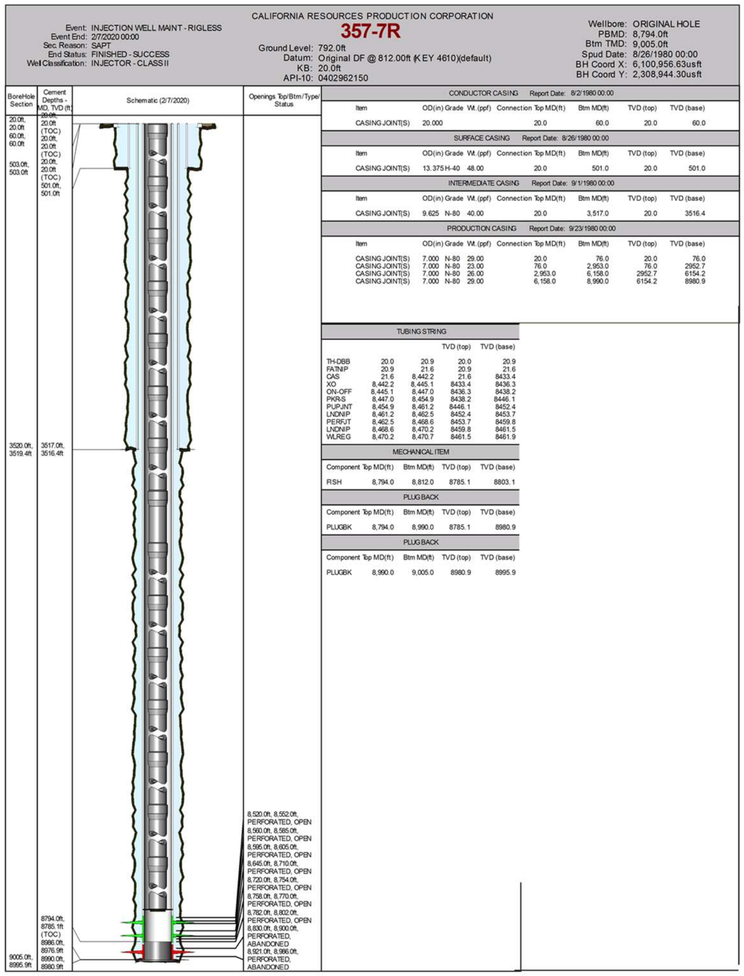
### *Packer Specifications*

| Packer Type and Material | Packer Setting Depth (feet bgs) | Length (inches) | Nominal Casing Weight (lbs/ft) | Packer Main Body Outer Diameter (inches) | Packer Inner Diameter (inches) |
|---|---|---|---|---|---|
| Baker-Hornet, Ni plated | 8,447 | 95.4 | 23-29 | 6.000 | 2.920 |

| Tensile Rating (lbs) | Burst Rating (psi) | Collapse Rating (psi) | Max. Casing Inner Diameter (inches) | Min. Casing Inner Diameter (inches) |
|---|---|---|---|---|
| 10,0000 | 8,000 | 8,000 | 6.466 | 6.184 |

### *Injection Well Construction Diagrams*

**Figure 1: Injection well 357-7R casing diagram.**




## <u>Pre-Injection Testing Plan – Injection Well</u>

The following tests and logs have been acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The tests and procedures are described below and in the Proposed Injection Well Construction Information section of the permit application.

### *Deviation Checks*

Deviation measurements were conducted approximately every 10 feet during construction of the well.

### *Tests and Logs*

*The following logs were acquired during the drilling and prior to the completion of the 357-7R well:*

- Array Compensated True Resistivity Log
- Spontaneous Potential Logs
- Caliper Logs
- Compensated Spectral Natural Gamma Log
- Spectral Density Dual Spaced Neutron Log
- Mud Log

*The following cased-hole logs were acquired after the drilling and completion of the 357-7R well:*

- Cement Bond Log
- Mechanical Integrity Tests (Temperature Log and SAPT)

***Demonstration of mechanical integrity***

Below is a summary of the tests to be performed prior to injection:

| Class VI Rule Citation | Rule Description | Test Description | Program Period |
|---|---|---|---|
| **40 CFR 146.89(a)(1)** | MIT - Internal | SAPT | Prior to operation |
| **40 CFR 146.87(a)(4)** | MIT - External | Temperature Log | Prior to operation |
| **40 CFR 146.87(a)(4)** | MIT - External | Radioactive Tracer | Prior to operation |

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

## Pre-Injection Testing Plan – Deep Monitoring Wells 327-7R-RD1 and 342-7R-RD1

Deep monitoring wells proposed for the Elk Hills A1-A2 Storage project have already been drilled and completed.

***Deviation Checks***

Deviation measurements for 342-7R-RD1 and 327-7R-RD1 were recorded approximately every 35 and 156 feet respectively, during construction of the well.

***Tests and Logs***

*The following logs were acquired during the drilling and prior to the completion of the 342-7R-RD1 and 327-7R-RD1 wells:*

- Array Compensated True Resistivity Log
- Spontaneous Potential Logs
- Caliper Logs

- Compensated Spectral Natural Gamma Log
- Spectral Density Dual Spaced Neutron Log

***Demonstration of mechanical integrity***

CTV will run mechanical integrity logs and tests prior to injection operations.

**Annulus Pressure Test Procedures for Injection Well 357-7R:**

1. The tubing/casing annulus (annulus) will be completely filled with liquid. The volume of fluid required will be measured;

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test;

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve; and

4. The annulus system must remain isolated for a period of no less than 60 minutes During the period of isolation measurements of pressure will be made at ten-minute intervals;

**Annulus Pressure Test Procedures for Monitoring Well 327-7R-RD1 & 342-7R-RD1:**

1. The tubing/casing annulus (annulus) will be completely filled with liquid. The volume of fluid required will be measured;

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test;

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system must be isolated from the source(annulus tank) by a closed valve; and

4. The annulus system must remain isolated for a period of no less than 60 minutes During the period of isolation measurements of pressure will be made at ten-minute intervals;

**Pressure Fall-Off Test Procedures:**

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV does not currently plan to complete pressure fall off testing. The Monterey Formation A1-A2 reservoir is a depleted oil and gas reservoir with known reservoir continuity, boundaries, and flow properties from decades of water and gas injection. CTV may address scaling through time by acidizing the well to clean out the perforations.

CTV will consider pressure fall-off testing if injection rate decreases, with a simultaneous injection pressure increase outside the results from computational modeling.

***Testing details***

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting-in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

Pressure sensors used for this test will be the wellhead gauges and a downhole gauge for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

# CLASS VI CONFINING ZONE PROPERTIES

# INJECTION WELL 357-7R
# 40 CFR 146.82(c)(4),(7) and 146.87(b)-(d)

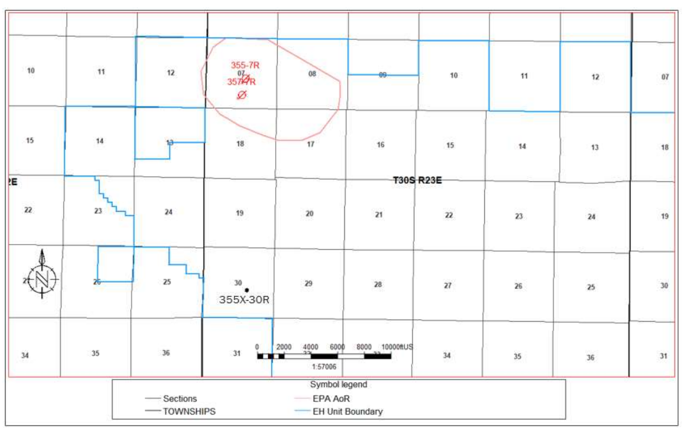
# ELK HILLS A1-A2 PROJECT

**<u>Confining Zone Chemical and Physical Characteristics</u>**

Core Analysis

Given the marine depositional environemnt and continuity of the Reef Ridge shale the 355X-30R well core analysis is used to characterize the Reef Ridge Shale in the AoR.

**Figure 1: Location of Reef Ridge core well 355X-30R.**




Mineralogy

Fourier Transform Infrared Spectroscopy (FTIR) is used to determine mineralogy of the confining zone from 36 points in one well (Figure 2). In the high clay intervals, the confining zone has an average of 29.5% total clay, 3.7% quartz, 14.5% potassium feldspar, albite and oligoclase as well as 47.1% silica polymorphs (Opal-CT, chert and Cristobalite).

**Figure 2: FTIR mineralogy for the Reef Ridge Shale in the 355X-30R well.**

OXY of Elk Hills, Inc. File No.: 57111-00102

Elk Hills Field

Core Lab PETROLEUM SERVICES

## FTIR Mineralogy

(Weight Percent)

| Depth (ft) | Density (g/cc) | Quartz | Albite | Oligoclase | Andesine | K-Feldspar | Calcite | Dolomite | Pyrite | Opal-A | Opal-CT | Chert | Cristobalite | Total Clay | Kaolinite | Chlorite | Illite+Smectite |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5285.5 | 2.51 | 12 | 9 | 0 | 10 | 10 | 0 | 0 | 0 | 0 | 26 | 0 | 0 | 33 | 5 | 3 | 25 |
| 5290.0 | 2.38 | 0 | 5 | 0 | 0 | 6 | 2 | 0 | 2 | 0 | 57 | 0 | 19 | 9 | 5 | 0 | 4 |
| 5291.8 | 2.51 | 0 | 7 | 0 | 3 | 9 | 3 | 0 | 3 | 0 | 39 | 11 | 0 | 25 | 9 | 0 | 16 |
| 5295.5 | 2.49 | 0 | 7 | 0 | 0 | 8 | 3 | 0 | 2 | 0 | 42 | 12 | 0 | 26 | 8 | 0 | 18 |
| 5299.2 | 2.52 | 0 | 0 | 0 | 0 | 5 | 0 | 35 | 1 | 0 | 35 | 0 | 19 | 5 | 4 | 0 | 1 |
| 5299.8 | 2.49 | 0 | 7 | 0 | 3 | 7 | 0 | 0 | 2 | 0 | 37 | 13 | 0 | 31 | 9 | 0 | 22 |
| 5302.2 | 2.44 | 0 | 8 | 0 | 0 | 7 | 0 | 0 | 2 | 0 | 39 | 7 | 13 | 24 | 9 | 0 | 15 |
| 5304.2 | 2.50 | 0 | 6 | 0 | 3 | 8 | 1 | 2 | 2 | 0 | 25 | 9 | 10 | 34 | 9 | 0 | 25 |
| 5308.1 | 2.51 | 0 | 7 | 0 | 6 | 5 | 0 | 3 | 0 | 0 | 23 | 17 | 0 | 39 | 11 | 0 | 28 |
| 5318.0 | 2.50 | 0 | 7 | 0 | 3 | 7 | 2 | 0 | 2 | 0 | 34 | 14 | 0 | 31 | 8 | 0 | 23 |
| 5325.0 | 2.52 | 12 | 0 | 0 | 9 | 7 | 0 | 3 | 0 | 0 | 23 | 0 | 0 | 46 | 14 | 0 | 32 |
| 5333.0 | 2.51 | 10 | 7 | 0 | 3 | 6 | 0 | 2 | 1 | 0 | 30 | 0 | 0 | 41 | 12 | 0 | 29 |
| 5336.9 | 2.37 | 0 | 5 | 0 | 0 | 4 | 0 | 0 | 2 | 0 | 63 | 0 | 20 | 6 | 4 | 0 | 2 |
| 5338.8 | 2.48 | 0 | 8 | 0 | 0 | 9 | 2 | 0 | 3 | 0 | 45 | 10 | 0 | 23 | 8 | 0 | 15 |
| 5341.2 | 2.81 | 0 | 0 | 0 | 0 | 3 | 3 | 75 | 1 | 0 | 0 | 12 | 0 | 6 | 0 | 0 | 6 |
| 5341.7 | 2.50 | 9 | 6 | 0 | 4 | 8 | 0 | 0 | 2 | 0 | 34 | 0 | 0 | 37 | 12 | 0 | 25 |
| 5346.1 | 2.78 | 0 | 0 | 0 | 0 | 0 | 4 | 70 | 0 | 0 | 0 | 18 | 0 | 8 | 0 | 0 | 8 |
| 5350.1 | 2.49 | 13 | 5 | 11 | 0 | 3 | 0 | 2 | 0 | 0 | 31 | 0 | 0 | 35 | 12 | 0 | 23 |
| 5356.0 | 2.51 | 16 | 7 | 0 | 5 | 8 | 0 | 2 | 0 | 0 | 25 | 0 | 0 | 37 | 11 | 0 | 26 |
| 5361.1 | 2.82 | 0 | 0 | 0 | 0 | 0 | 2 | 81 | 1 | 0 | 0 | 10 | 0 | 6 | 0 | 0 | 6 |
| 5364.6 | 2.37 | 0 | 0 | 0 | 0 | 9 | 0 | 0 | 1 | 0 | 58 | 0 | 22 | 10 | 5 | 0 | 5 |
| 5371.0 | 2.55 | 0 | 7 | 0 | 2 | 10 | 2 | 0 | 3 | 0 | 25 | 16 | 0 | 35 | 9 | 0 | 26 |
| 5380.6 | 2.37 | 0 | 7 | 0 | 0 | 4 | 1 | 0 | 0 | 0 | 58 | 0 | 16 | 14 | 5 | 0 | 9 |
| 5381.0 | 2.49 | 10 | 5 | 12 | 8 | 8 | 0 | 0 | 0 | 0 | 29 | 0 | 0 | 28 | 4 | 0 | 24 |
| 5383.3 | 2.41 | 0 | 6 | 0 | 0 | 8 | 1 | 1 | 1 | 0 | 47 | 0 | 17 | 19 | 7 | 0 | 12 |
| 5386.4 | 2.39 | 0 | 7 | 0 | 0 | 7 | 1 | 0 | 1 | 0 | 52 | 0 | 17 | 15 | 6 | 0 | 9 |
| 5387.4 | 2.45 | 0 | 7 | 0 | 2 | 7 | 2 | 2 | 0 | 0 | 32 | 7 | 15 | 26 | 8 | 0 | 18 |
| 5391.4 | 2.40 | 0 | 8 | 0 | 0 | 6 | 0 | 0 | 1 | 0 | 51 | 5 | 16 | 13 | 6 | 0 | 7 |
| 5398.6 | 2.51 | 11 | 6 | 0 | 5 | 6 | 2 | 2 | 0 | 0 | 28 | 0 | 0 | 40 | 14 | 0 | 26 |
| 5406.5 | 2.49 | 0 | 6 | 0 | 2 | 7 | 5 | 0 | 0 | 0 | 31 | 13 | 0 | 36 | 11 | 0 | 25 |
| 5410.9 | 2.41 | 0 | 7 | 0 | 0 | 8 | 2 | 0 | 1 | 0 | 46 | 0 | 16 | 20 | 7 | 0 | 13 |
| 5416.2 | 2.45 | 0 | 8 | 0 | 0 | 7 | 0 | 0 | 0 | 0 | 44 | 10 | 0 | 31 | 9 | 0 | 22 |
| 5418.5 | 2.46 | 5 | 6 | 0 | 2 | 8 | 2 | 0 | 0 | 0 | 30 | 0 | 11 | 36 | 11 | 0 | 25 |
| 5423.6 | 2.51 | 0 | 7 | 0 | 0 | 8 | 3 | 0 | 2 | 0 | 33 | 15 | 0 | 32 | 7 | 0 | 25 |
| 5433.5 | 2.51 | 12 | 6 | 0 | 7 | 8 | 0 | 0 | 0 | 0 | 26 | 0 | 0 | 41 | 12 | 0 | 29 |
| 5447.5 | 2.46 | 0 | 8 | 0 | 0 | 6 | 0 | 0 | 1 | 0 | 45 | 13 | 0 | 27 | 8 | 0 | 19 |

Permeability

Table 1 shows the Reef Ridge Shale permeability for the 355X-30R well.

**Table 1: Permeability and porosity for the Reef Ridge Shale in the 355X-30R well from mercury injection capillary pressure data.**

| Sample | Depth (ft) | Porosity (dec) | Permeability (mD) |
|---|---|---|---|
| TEST1 | 5290 | 0.0586 | 0.00007 |
| TEST2 | 5299.2 | 0.0351 | 0.00003 |
| TEST3 | 5338.8 | 0.0922 | 0.0002 |
| TEST4 | 5361.1 | 0.137 | 0.0917 |
| TEST5 | 5364.4 | 0.0536 | 0.00006 |
| TEST6 | 5380.6 | 0.0611 | 0.00007 |
| TEST7 | 5383.3 | 0.0794 | 0.00012 |
| TEST8 | 5386.4 | 0.0541 | 0.00006 |
| TEST9 | 5391.4 | 0.102 | 0.0002 |
| TEST10 | 5416.2 | 0.0894 | 0.0002 |
| TEST11 | 5447.5 | 0.0806 | 0.00011 |
| Average | 5368.99 | 0.07665 | 0.00844 |

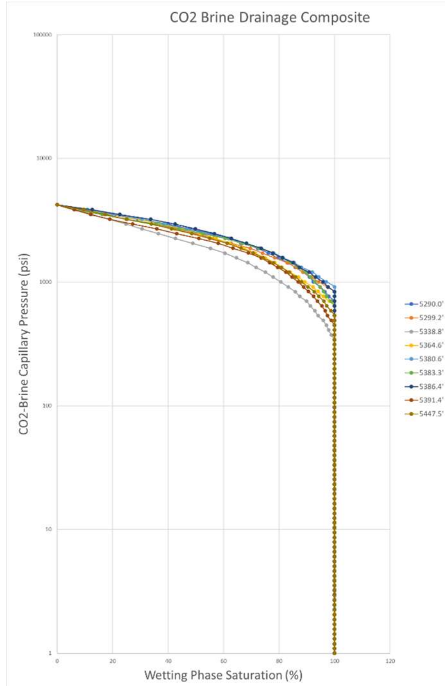
The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points in one well.

The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in one well.

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for the $CO_2$ to overcome capillary and interfacial forces and enter the pore space containing the water.

The capillary pressure of the confining zone is 4,220 PSI in a $CO_2$-brine system based on 11 mercury injection capillary pressure core data points in one well (Figure 3). The capillary pressure was determined by applying $CO_2$-brine corrections to the air-mercury data. An interfacial tension of 480 dynes/cm was used for air-mercury and 30 dynes/cm was used to convert to $CO_2$-brine. A cosine of contact angle of 0.766 and 0.866 were also used for air-mercury and $CO_2$-brine respectively.

**Figure 3: Capillary pressure graph for the 355X-30R well.**



# CLASS VI CORE ANALYSIS

# INJECTION WELL 357-7R
# 40 CFR 146.82(c)(4),(7) and 146.87(b)

# ELK HILLS A1-A2 PROJECT

## Monterey Formation A1-A2 Core Analysis

### Mineralogy

X-ray diffraction data has been compiled and compared from 9 wells with a total of 108 data points. Clay speciation has been found to be consistent throughout the Area of Review. Offset well 367-7R supplies an example of the mineralogy for the reservoir (Figure 1). The location of well 367-7R is shown on the map in Figure 3.

**Figure 1: 367-7R mineralogy for the Monterey Formation A1-A2 reservoir.**

BECHTEL PETROLEUM OPERATIONS, INC.
367-7R
ELK HILLS FIELD

FILE # 17019

MINERALOG™ ANALYSIS (WEIGHT %)

| DEPTH | GDI | SAMP. WT | QTZ | CHRT | OP-A | OP-CT | ALB | OLIG | ANDE | KSPAR | CALC | DOLO | PYR | KAOL | CHLOR | ILL/SMEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8551.9 | 2.62 | 8.34 | 30 | 13 | 0 | 0 | 17 | 0 | 2 | 21 | 2 | 0 | 1 | 0 | 0 | 14 |
| 8552.0 | 2.62 | 9.41 | 28 | 13 | 0 | 0 | 14 | 10 | 0 | 15 | 3 | 0 | 0 | 0 | 3 | 14 |
| 8554.1 | 2.62 | 10.73 | 45 | 0 | 0 | 0 | 19 | 0 | 2 | 20 | 4 | 0 | 0 | 0 | 0 | 10 |
| 8560.6 | 2.62 | 11.57 | 44 | 0 | 0 | 0 | 15 | 11 | 0 | 17 | 5 | 0 | 0 | 2 | 0 | 6 |
| 8570.0 | 2.62 | 8.32 | 43 | 0 | 0 | 0 | 17 | 8 | 4 | 17 | 3 | 0 | 0 | 0 | 0 | 8 |
| 8593.0 | 2.62 | 14.88 | 45 | 0 | 0 | 0 | 15 | 11 | 0 | 18 | 4 | 0 | 0 | 0 | 0 | 7 |
| 8608.9 | 2.60 | 18.83 | 21 | 21 | 0 | 0 | 15 | 0 | 10 | 14 | 2 | 0 | 0 | 0 | 0 | 17 |
| 8634.9 | 2.62 | 21.65 | 44 | 0 | 0 | 0 | 16 | 13 | 1 | 17 | 3 | 0 | 0 | 0 | 0 | 6 |
| 8648.6 | 2.62 | 14.16 | 47 | 0 | 0 | 0 | 18 | 3 | 5 | 19 | 3 | 0 | 0 | 0 | 0 | 5 |
| 8649.2 | 2.62 | 15.56 | 49 | 0 | 0 | 0 | 18 | 0 | 4 | 18 | 3 | 0 | 0 | 2 | 0 | 6 |
| 8649.8 | 2.62 | 8.73 | 50 | 0 | 0 | 0 | 17 | 0 | 4 | 17 | 1 | 2 | 0 | 3 | 0 | 6 |
| 8650.9 | 2.62 | 11.24 | 45 | 0 | 0 | 0 | 14 | 9 | 4 | 17 | 2 | 1 | 0 | 2 | 0 | 6 |
| 8651.8 | 2.62 | 8.75 | 46 | 0 | 0 | 0 | 16 | 0 | 6 | 19 | 3 | 0 | 0 | 0 | 0 | 10 |
| 8656.0 | 2.63 | 23.81 | 38 | 0 | 0 | 0 | 14 | 10 | 4 | 14 | 12 | 2 | 0 | 0 | 0 | 6 |
| 8702.6 | 2.61 | 10.56 | 40 | 13 | 0 | 0 | 15 | 0 | 5 | 18 | 2 | 0 | 0 | 0 | 0 | 7 |

GDI = GRAIN DENSITY INDEX
SAMP. WT = WEIGHT OF FRESH SAMPLE CRUSHED FOR ANALYSIS
QTZ = QUARTZ
CHRT = CHERT
OP-A = OPAL-A
OP-CT = OPAL-CT
ALB = ALBITE
OLIG = OLIGOCLASE

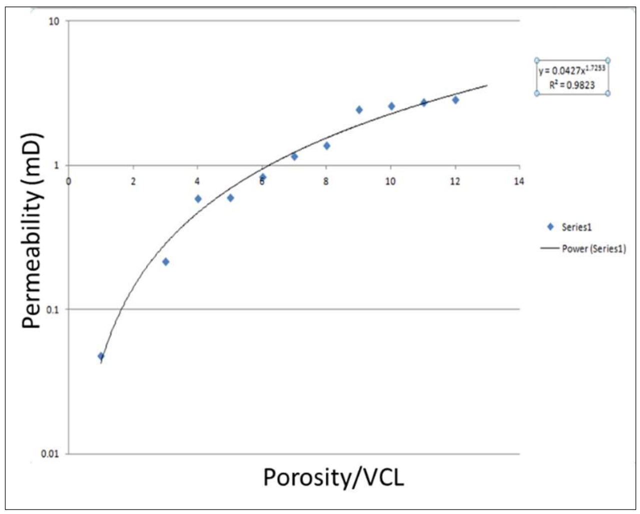
ANDE = ANDESINE
KSPAR = POTASSIUM FELDSPAR
CALC = CALCITE
DOLO = DOLOMITE
PYR = PYRITE
KAOL = KAOLINITE
CHLOR = CHLORITE
ILL/SMEC = ILLITE + SMECTITE

Clean reservoir sand intervals have an average of 43% quartz, 38% potassium feldspar, albite and oligoclase as well as 7% total clay.

Permeability

Log-derived permeability is determined by applying a core-based transform that utilizes mercury injection capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy (FTIR). Core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. An example of the transform from core data is illustrated below (Figure 2).

**Figure 2: Permeability function for the Monterey Formation A1-A2 reservoir. The function was defined by mercury injection capillary pressure analysis. Continuous permeability for the static model is calculated based on open-hole well log derived porosity and clay volume.**




Example core report data of the MICP porosity and permeability from offset well 317-8R (Table 1). The location of well 317-8R is shown on the map in Figure 3.

**Figure 3: Location of wells 367-7R and 317-8R.**

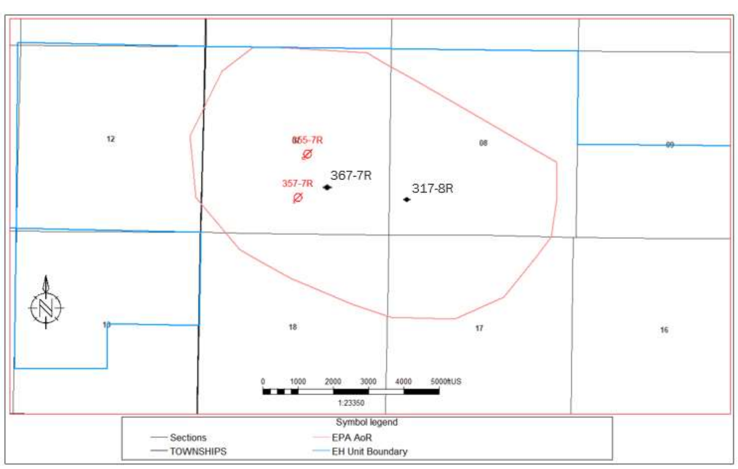


**Table 1: Example core report data of the MICP porosity and permeability from well 317-8R.**

| DEPTH | ANALYSIS_LAB | DATE | SAMPLE_ID | CKHA | CPOR | CKHA_C | SYSTEM |
|---|---|---|---|---|---|---|---|
| feet | | | | mD | % | mD | |
| 8865 | CORE LABORATORIES | 8/6/1975 | 1 | 215 | 24 | 160 | air-brine |
| 8868 | CORE LABORATORIES | 8/6/1975 | 2 | 72 | 20.7 | 58 | air-brine |
| 8869 | CORE LABORATORIES | 8/6/1975 | 3 | 21 | 18.7 | 13 | air-brine |
| 8948 | CORE LABORATORIES | 8/6/1975 | 4 | 42 | 17 | 39 | air-brine |
| 8952 | CORE LABORATORIES | 8/6/1975 | 5 | 54 | 17.9 | 50 | air-brine |
| 8960 | CORE LABORATORIES | 8/6/1975 | 6 | 39 | 16.5 | 37 | air-brine |
| 8971 | CORE LABORATORIES | 8/6/1975 | 7 | 24 | 17.2 | 19 | air-brine |
| 8974 | CORE LABORATORIES | 8/6/1975 | 8 | 91 | 20.1 | 75 | air-brine |

# CLASS VI INJECTION ZONE PROPERTIES

## INJECTION WELL 357-7R
## 40 CFR 146.82(c)(4),(7) and 146.87(b)-(d)

## ELK HILLS A1-A2 PROJECT

## Injection Zone Chemical and Physical Properties

Water Geochemistry

Produced water geochemistry shows that injection zone total dissolved solids are 24,000 -25,000 milligrams per liter (Figure 1). The Monterey Formation A1-A2 reservoir is depleted due to oil and gas production and has a low current water saturation. As such, the water sample shown in Figure 1 was taken from a sand directly underneath the Monterey Formation A1-A2 reservoir.

**Figure 1: Water analysis report for the Monetary Formation reservoir from well 381-17R.**

BAKER HUGHES

Pacific Coast Area Laboratory
3901 Fanucchi Way E,
Shafter, California 93263

Upstream Chemicals

REPORT DATE: 5/15/2019

**COMPLETE WATER ANALYSIS REPORT** SSP v.2010

| | | | |
|---|---|---|---|
| CUSTOMER: | CALIFORNIA RESOURCES ELK HILLS | ACCOUNT REP: | DENNIS MORSE |
| DISTRICT: | TAFT | SAMPLE ID: | 201906016726 |
| AREA/LEASE: | ELK HILLS | SAMPLE DATE: | 5/2/2019 |
| SAMPLE POINT NAME | 381-17R | ANALYSIS DATE: | 5/9/2019 |
| SITE TYPE: | WELL SITES | ANALYST: | SR/IL |
| SAMPLE POINT DESCRIPTION: | NOT PROVIDED | | |

**CALIFORNIA RESOURCES ELK HILLS, ELK HILLS, 381-17R**

FIELD DATA

| | |
|---|---|
| Initial Temperature (°F): | 250 |
| Final Temperature (°F): | 120 |
| Initial Pressure (psi): | 100 |
| Final Pressure (psi): | 15 |
| **pH:** | |
| pH at time of sampling: | 7.4 |

| ALKALINITY BY TITRATION: | mg/L | meq/L |
|---|---|---|
| Bicarbonate ($HCO_3^-$): | 1300.0 | 21.3 |
| Carbonate ($CO_3^{2-}$): | ND | |
| Hydroxide ($OH^-$): | ND | |

| | |
|---|---|
| aqueous $CO_2$ (ppm): | 1660.0 |
| aqueous $H_2S$ (ppm): | 0.0 |
| aqueous O2 (ppb): | ND |
| Calculated TDS (mg/L): | 24877 |
| Density/Specific Gravity (g/cm$^3$): | 1.0143 |
| Measured Specific Gravity | ND |
| Conductivity (mmhos): | 38.6 |
| Resistivity: | ND |
| MCF/D: | No Data |
| BOPD: | No Data |
| BWPD: | No Data |

ANALYSIS OF SAMPLE

| ANIONS: | mg/L | meq/L |
|---|---|---|
| Chloride ($Cl^-$): | 14063.4 | 396.7 |
| Sulfate ($SO_4^{2-}$): | 28.5 | 0.6 |
| Borate ($H_3BO_3$): | ND | |
| Fluoride ($F^-$): | ND | |
| Bromide ($Br^-$): | ND | |
| Nitrite ($NO_2^-$): | ND | |
| Nitrate ($NO_3^-$): | ND | |
| Phosphate ($PO_4^{3-}$): | 0.9 | 0.0 |
| Silica ($SiO_2$): | 76.3 | |

| ORGANIC ACIDS: | mg/L | meq/L |
|---|---|---|
| Formic Acid: | ND | |
| Acetic Acid: | ND | |
| Propionic Acid: | ND | |
| Butyric Acid: | ND | |
| Valeric Acid: | ND | |

Anion/Cation Ratio: 1.03

| CATIONS: | mg/L | meq/L |
|---|---|---|
| Sodium ($Na^+$): | 9110.0 | 396.4 |
| Potassium ($K^+$): | 136.0 | 3.5 |
| Magnesium ($Mg^{2+}$): | 29.7 | 2.4 |
| Calcium ($Ca^{2+}$): | 80.6 | 4.0 |
| Strontium ($Sr^{2+}$): | 32.2 | 0.7 |
| Barium ($Ba^{2+}$): | 17.7 | 0.3 |
| Iron ($Fe^{2+}$): | 1.9 | 0.1 |
| Manganese ($Mn^{2+}$): | 0.1 | 0.0 |
| Lead ($Pb^{2+}$): | ND | |
| Zinc ($Zn^{2+}$): | ND | |
| Aluminum ($Al^{3+}$): | ND | |
| Chromium ($Cr^{3+}$): | ND | |
| Cobalt ($Co^{2+}$): | ND | |
| Copper ($Cu^{2+}$): | ND | |
| Molybdenum ($Mo^{2+}$): | ND | |
| Nickel ($Ni^{2+}$): | ND | |
| Tin ($Sn^{2+}$): | ND | |
| Titanium ($Ti^{2+}$): | ND | |
| Vanadium ($V^{2+}$): | ND | |
| Zirconium ($Zr^{2+}$): | ND | |
| Lithium (Li): | ND | |
| Total Hardness: | 373 | N/A |

ND = Not Determined

SCALE PREDICTIONS BASED ON FIELD PROVIDED DATA; FUTHER MODELING MAY BE REQUIRED FOR VALIDATION OF SCALE PREDICTION RESULTS.

| Conditions | | Barite ($BaSO_4$) | | Calcite ($CaCO_3$) | | Gypsum ($CaSO_4 \cdot 2H_2O$) | | Anhydrite ($CaSO_4$) | |
|---|---|---|---|---|---|---|---|---|---|
| Temp | Press. | Index | Amt (ptb) | Index | Amt (ptb) | Index | Amt (ptb) | Index | Amt (ptb) |
| 120°F | 15 psi | 0.69 | 7.431 | 0.80 | 50.709 | -3.01 | 0.000 | -3.08 | 0.000 |
| 134°F | 24 psi | 0.61 | 6.908 | 0.81 | 51.219 | -3.01 | 0.000 | -3.00 | 0.000 |
| 149°F | 34 psi | 0.54 | 6.406 | 0.87 | 53.173 | -2.99 | 0.000 | -2.92 | 0.000 |
| 163°F | 43 psi | 0.48 | 5.938 | 0.94 | 55.496 | -2.98 | 0.000 | -2.83 | 0.000 |
| 178°F | 53 psi | 0.43 | 5.517 | 1.02 | 57.796 | -2.96 | 0.000 | -2.74 | 0.000 |
| 192°F | 62 psi | 0.40 | 5.151 | 1.11 | 59.914 | -2.94 | 0.000 | -2.64 | 0.000 |
| 207°F | 72 psi | 0.36 | 4.844 | 1.20 | 61.788 | -2.92 | 0.000 | -2.54 | 0.000 |
| 221°F | 81 psi | 0.34 | 4.598 | 1.31 | 63.519 | -2.89 | 0.000 | -2.44 | 0.000 |
| 236°F | 91 psi | 0.32 | 4.412 | 1.41 | 65.003 | -2.87 | 0.000 | -2.33 | 0.000 |
| 250°F | 100 psi | 0.31 | 4.283 | 1.52 | 66.200 | -2.84 | 0.000 | -2.22 | 0.000 |

| Conditions | | Celestite ($SrSO_4$) | | Halite (NaCl) | | Iron Sulfide (FeS) | | Iron Carbonate ($FeCO_3$) | |
|---|---|---|---|---|---|---|---|---|---|
| Temp | Press. | Index | Amt (ptb) | Index | Amt (ptb) | Index | Amt (ptb) | Index | Amt (ptb) |
| 120°F | 15 psi | -1.74 | 0.000 | -2.74 | 0.000 | -8.70 | 0.000 | 1.09 | 1.293 |
| 134°F | 24 psi | -1.72 | 0.000 | -2.75 | 0.000 | -8.78 | 0.000 | 1.13 | 1.304 |
| 149°F | 34 psi | -1.70 | 0.000 | -2.75 | 0.000 | -8.80 | 0.000 | 1.21 | 1.321 |
| 163°F | 43 psi | -1.68 | 0.000 | -2.75 | 0.000 | -8.80 | 0.000 | 1.30 | 1.337 |
| 178°F | 53 psi | -1.65 | 0.000 | -2.75 | 0.000 | -8.78 | 0.000 | 1.39 | 1.351 |
| 192°F | 62 psi | -1.61 | 0.000 | -2.75 | 0.000 | -8.74 | 0.000 | 1.48 | 1.361 |
| 207°F | 72 psi | -1.57 | 0.000 | -2.74 | 0.000 | -8.70 | 0.000 | 1.57 | 1.370 |
| 221°F | 81 psi | -1.53 | 0.000 | -2.74 | 0.000 | -8.64 | 0.000 | 1.66 | 1.377 |
| 236°F | 91 psi | -1.48 | 0.000 | -2.73 | 0.000 | -8.58 | 0.000 | 1.75 | 1.383 |
| 250°F | 100 psi | -1.42 | 0.000 | -2.72 | 0.000 | -8.51 | 0.000 | 1.83 | 1.388 |

Note 1: When assessing the severity of the scale problem, both the saturation index (SI) and amount of scale must be considered

Note 2: Precipitation of each scale is considered separately. Total scale will be less than the sum of the amounts of the eight (8) scales.

Note 3: Saturation Index predictions on this sheet use pH and alkalinity; %$CO_2$ is not included in the calculations.

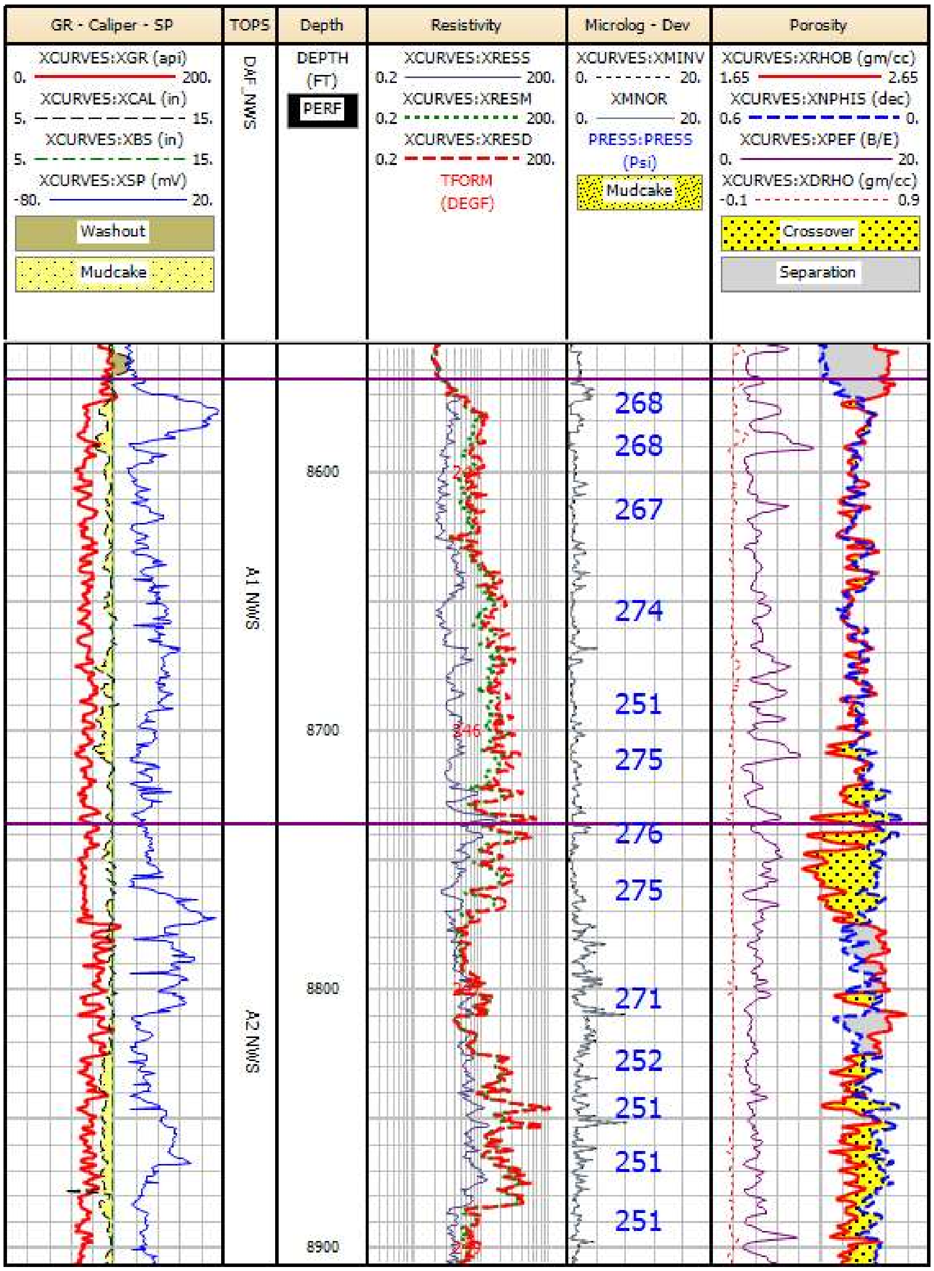
ESSI ScaleSoftPitzer™ SSP2010

Comments: Zn<0.02

Reservoir Pressure

Monterey Formation A1-A2 reservoir pressure taken by a wireline formation pressure testing tool in well 364X-7R is shown in Figure 2. Final wireline pressure is plotted numerically in the Microlog track showing pressure between 200 - 300 PSI. The location of well 364X-7R is shown in Figure 4.

**Figure 2: Monterey Formation A1-A2 pressure from well 364X-7R.**



Below (Figure 3) is an example build-up test from well 364X-7R taken at 8578.86 feet measured depth in the Monterey Formation A1-A2 reservoir. The location of well 364X-7R is shown in Figure 4.

**Figure 3: Pressure build-up test for the Monterey Formation A1-A2 reservoir in well 364X-7R.**

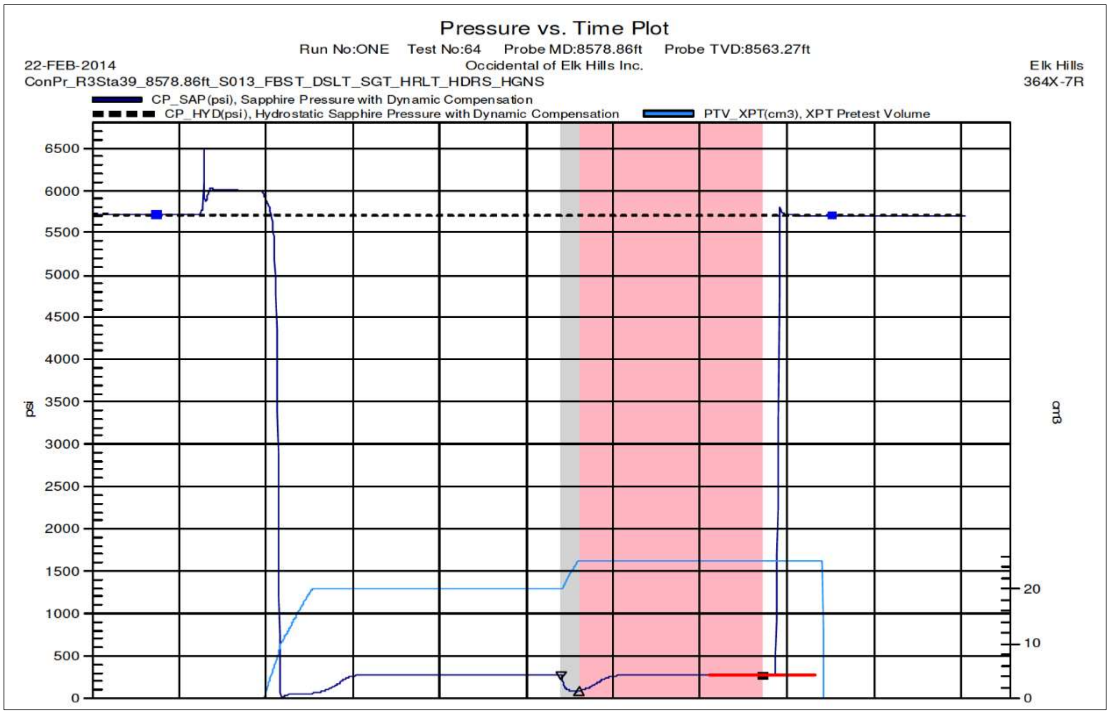
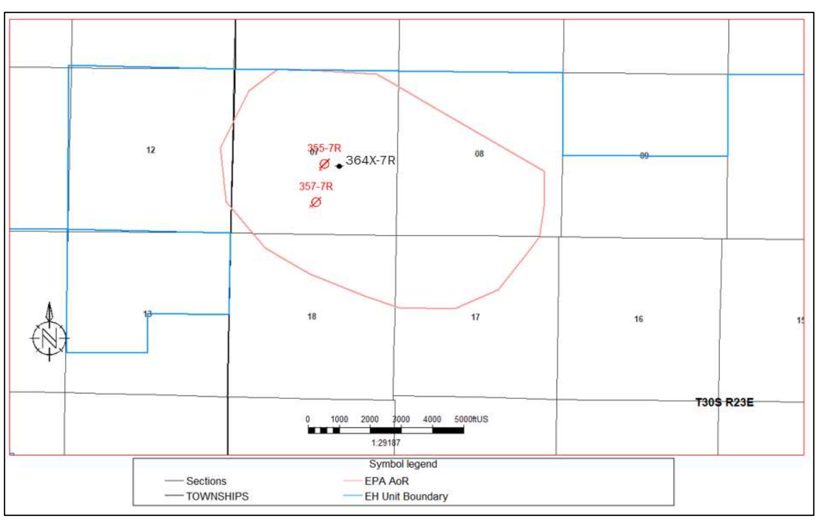



**Figure 4: Location of well 364X-7R.**



Fracture Gradient

A fracture gradient of 0.97 PSI per foot at 9,428 feet measured depth was acquired in well 327-7R-RD1 (Figure 5). The 327-7R-RD1 well location is shown on the map in Figure 6.

**Figure 5: A fracture gradient of 0.97 PSI per foot was measured in well 327-7R-RD1.**

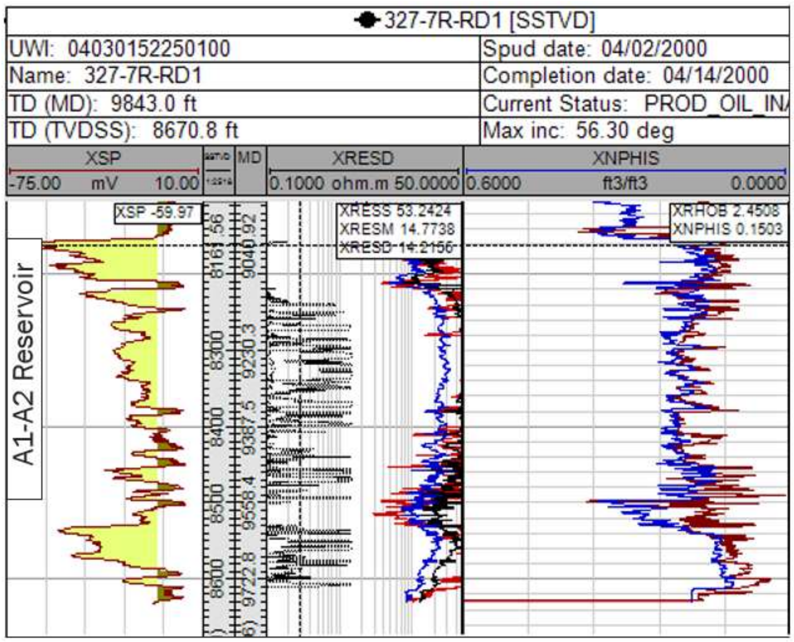
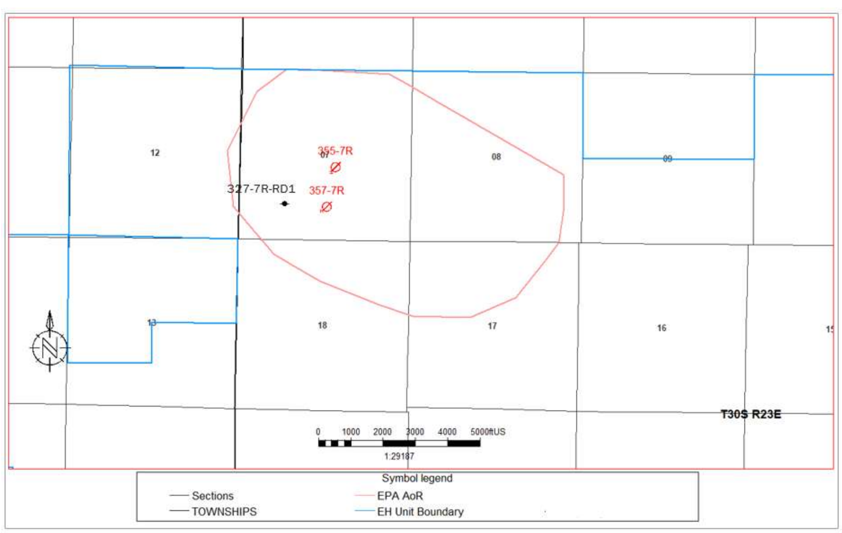



**Figure 6: Location of well 327-7R-RD1.**



## Class VI UIC Pre-Operational Testing

This submission is for:

Project ID: R09-CA-0003

Project Name: CRC CalCapture A1-A2

Current Project Phase: Pre-Injection Prior to Construction

Proposed Pre-Operational Testing: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/PreOpTest-08-02-2021-1950/Testing--Plan.pdf

Proposed Pre-Operational Testing Schedule: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/PreOpTest-08-02-2021-1950/Testing--Schedule.pdf

State Pre-Operational Test Results: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/PreOpTest-08-02-2021-1950/State--Requirements.pdf

## Well and Cement Logs

1. Number of Wells Tested: 1

### Well #1

Well Location: 35.32802963 Latitude -119.5449982 Longitude Well Name: 357-7R

Select Well and Cement Logs and Tests Conducted Under the Pre-Operational Testing Program:

During Drilling: Deviation Checks

Before Installation of Long String Casing: Resistivity Spontaneous Potential Porosity Caliper Gamma Ray

After Installation of Long String Casing: Cement Bond Variable Density Log

2. Number of Reports to be Uploaded: 1

### Report #1

Report File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/PreOpTest-08-02-2021-1950/357-7R--Logging--and--Testing.pdf

Description of the File Uploaded: Log analyst report for all logs conducted before and after instalation of long string casing.

## MITs

1. Number of Wells Tested: 1

### Well #1

Well Location: 35.32802963 Latitude -119.5449982 Longitude Well Name: 357-7R

Select the Test(s) Conducted to Demonstrate Internal and External Mechanical Integrity: Pressure Test with Liquid or Gas Tracer Survey (e.g., Oxygen Activation Log), Enter Name: Radioactive tracer Temperature Log

2. Number of Reports to be Uploaded: 1

### Report #1

Report File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/PreOpTest-08-02-2021-1950/357-7R--Mechanical--Integrity--Testing.pdf

Description of the File Uploaded: MIT (radioactive tracer and temperature) and SAPT.

## Core Analyses

1. Number of Cores Tested: 1

### Core #1

Whole Core Core ID: NA

Core Location: 35.32898331 / 35.32786179 Latitude -119.5422287 / -119.5350342 Longitude Well Name: 367-7R / 317-8R

Elevations Specified By: Attached File

https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/PreOpTest-08-02-2021-1950/367-7R--and--317-8R--Core--Depth.csv

Select All Properties/Tests Included in Uploaded Reports:

Total Porosity Horizontal Permeability

Lithology

2. Number of Reports to be Uploaded: 1

### Report #1

Report File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/PreOpTest-08-02-2021-

1950/Core--Analysis.pdf

Description of the File Uploaded: Log analyst report for Monterey Formation A1-A2 core analysis.

## Formation Characterization

1a. Number of Geologic Formations (or Distinct Units/Zones) within the Injection Zone: 1

### Injection Formation #1

Formation/Zone Name: Monterey Formation A1-A2

Select Properties Measured: Fluid Temperature pH Conductivity Reservoir Pressure Static Fluid Level Fracture Pressure

1b. Number of Geologic Formations (or Distinct Units/Zones) within the Confining Zone: 1

### Confining Formation #1

Formation/Zone Name: Reef Ridge

Select Properties Measured: Other Physical/Chemical Parameters of the Formation (list): Core analysis with lithology, permeability and capillary pressure.

2. Number of Reports to be Uploaded: 2

### Report #1

Report File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/PreOpTest-08-02-2021-1950/Injection--Zone--Properties.pdf

Description of the File Uploaded: Injection zone properties.

### Report #2

Report File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/PreOpTest-08-02-2021-1950/Confining--Zone--Properties.pdf

Description of the File Uploaded: Confining zone properties

## Injection Well Testing

1. Number of Wells Tested: 1

### Well #1

Well Location: 35.32802963 Latitude -119.5449982 Longitude Well Name: 357-7R

Select Injection Well Tests Conducted: Other: 357-7R gas injection and pressure build-up test.

2. Number of Reports to be Uploaded: 1

### Report #1

Report File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/PreOpTest-08-02-2021-1950/357-7R--Well--Testing.pdf

Description of the File Uploaded: Well 357-7R has injected 3.5 billion cubic feet of gas.

Supporting Data File(s): https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/PreOpTest-08-02-2021-1950/Attachment--G--Construction--Details.pdf

## Complete Submission

Authorized submission made by: Travis Hurst

For confirmation a read-only copy of your submission will be emailed to: travis.hurst@crc.com

California is not a primacy state that has pre-operational testing requirements.

**CLASS VI TESTING**

**INJECTION WELL 357-7R**
**40 CFR 146.87**

**ELK HILLS A1-A2 PROJECT**

## Pre-Operational Testing Plan

The 357-7R and 355-7R injection wells are being repurposed for the CTV Elk Hills A1-A2 project. These wells have been approved by California Geologic Energy Management (CalGEM) for Class II injection of gas for pressure maintenance.

The Monterey Formation A1-A2 reservoir was discovered in the 1970's and has since been developed with water and gas injection for pressure maintenance. Operational history of the field has provided a robust dataset to fully characterize the reservoir, confining layer and USDW with (Table 1).

**Table 1: Site characterization data for the Elk Hills A1-A2 project**.

| | |
|---|---|
| **Deviation Checks** | **Provided** |
| **Cement Bond Log** | **Provided** |
| **Open-hole Well Logs** | **Provided** |
| **Mechanical Integrity Test** | **Provided** |
| **Standard Annulus Pressure Test (SAPT)** | **Provided** |
| **Injection Zone and Confining Layer Core** | **Provided** |
| **Reservoir Conditions and Fluid** | **Provided** |
| **Injection Zone and Confining Layer Fracture Gradients** | **Provided** |
| **Pressure Testing** | **Provided** |

**CLASS VI TESTING**

**INJECTION WELL 357-7R**
**40 CFR 146.87**

**ELK HILLS A1-A2 PROJECT**

## Pre-Operational Testing Plan

The 357-7R and 355-7R injection wells are being repurposed for the CTV Elk Hills A1-A2 project. These wells have been approved by California Geologic Energy Management (CalGEM) for Class II injection of gas for pressure maintenance.

The Monterey Formation A1-A2 reservoir was discovered in the 1970's and has since been developed with water and gas injection for pressure maintenance. Operational history of the field has provided a robust dataset to fully characterize the reservoir, confining layer and USDW with (Table 1).

**Table 1: Site characterization data for the Elk Hills A1-A2 project**.

| | |
|---|---|
| **Deviation Checks** | **Provided** |
| **Cement Bond Log** | **Provided** |
| **Open-hole Well Logs** | **Provided** |
| **Mechanical Integrity Test** | **Provided** |
| **Standard Annulus Pressure Test (SAPT)** | **Provided** |
| **Injection Zone and Confining Layer Core** | **Provided** |
| **Reservoir Conditions and Fluid** | **Provided** |
| **Injection Zone and Confining Layer Fracture Gradients** | **Provided** |
| **Pressure Testing** | **Provided** |

**ATTACHMENT A: CLASS VI PERMIT APPLICATION NARRATIVE**
**40 CFR 146.82(a)**

**Elk Hills A1-A2 Storage Project**

## Project Background and Contact Information

Carbon TerraVault 1 LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate two $CO_2$ geologic sequestration wells at the Elk Hills Oil Field (EHOF) located in Kern County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81). CTV is not requesting an injection depth waiver or aquifer exemption expansion.

CTV forecasts the potential $CO_2$ stored in the Monterey Formation at 0.25 - 0.75 million tonnes annually for 15 years with injection starting in 2024. The anthropogenic $CO_2$ will be sourced from either the Elk Hills 550 MW natural gas combined cycle power plant, renewable diesel refineries, and/or other sources in the EHOF area.

The EHOF storage site is 20 miles west of Bakersfield (Figure 1) in the San Joaquin Basin. CTV operates and owns ~100% of the surface, mineral and pore space rights at the EHOF. The project will consist of two existing injectors, surface facilities, and monitoring wells. This supporting documentation applies to the two injection wells.

CTV has communicated project details and submitted regulatory documents to County and State agencies:

1. Kern County Planning and Natural Resource Development

   Director

   Lorelei Oviatt: (661)-862-8866

2. California Natural Resource Agency

   Deputy Secretary for Energy

   Matt Baker: (916) 653-5356

## Class VI - Wells used for Geologic Sequestration of $CO_2$

| **GSDT Submission - Project Background and Contact Information** |
|---|
| ***GSDT Module:*** Project Information Tracking<br>***Tab(s):*** General Information tab; Facility Information and Owner/Operator Information tab<br><br>Please use the checkbox(es) to verify the following information was submitted to the GSDT:<br>☒ Required project and facility details ***[40 CFR 146.82(a)(1)]*** |

## <u>Site Characterization</u>

### *Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]*

Elk Hills Field History

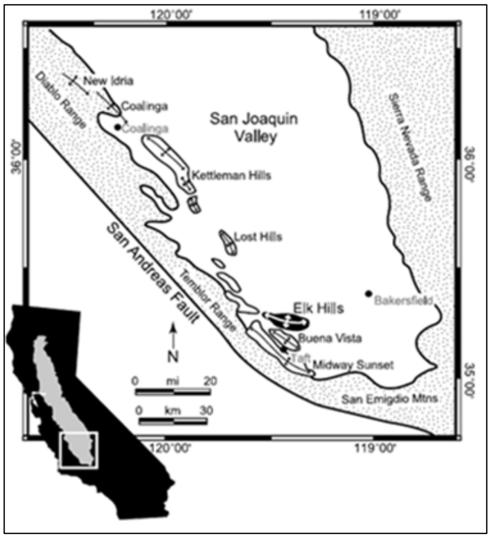
Discovered in the early 1900's the EHOF served as a Naval Petroleum Reserve (NPR-1) and was owned by the Navy and Department of Energy until its sale to Occidental Petroleum (Oxy) in 1998. In December 2014, Oxy spun off its California-specific assets including EHOF and the staff responsible for its development and operations to newly incorporated CRC. The Monterey Formation A1-A2 sequestration reservoir was discovered in the 1970's and has been developed with primary drilling and improved recovery with water and gas injection.

Elk Hills Geology Overview

The EHOF is located 20 miles west of Bakersfield in the fore-arc San Joaquin Basin (Figure 1). This continuously subsiding basin is a sediment filled depression that lies between the Sierra Nevada and Coast Ranges and is 450 miles long by 35 miles wide. The basin dates to the early Mesozoic (65 million years ago) when subduction was occurring off the coast of California. The plate tectonic configuration changed during the tertiary and the oceanic trench was transformed into the San Andreas fault, a zone of right-lateral strike-slip.

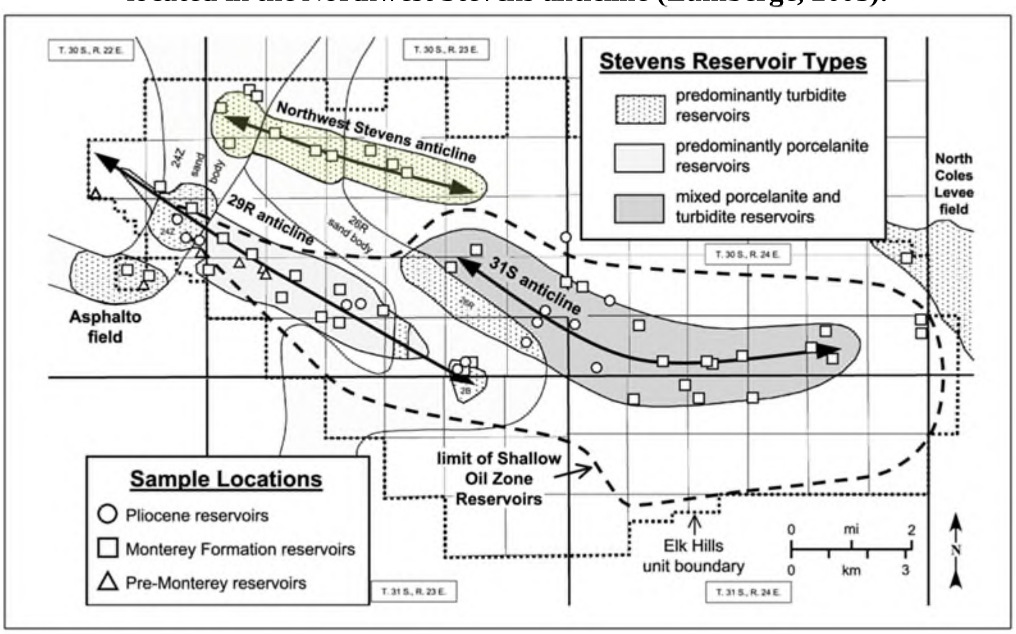
The Sierra Nevada, the most eastern province, is an immense section of granite that has been uplifted and tilted to the west. The Coast Ranges, which compose the western most province, are an anticlinorium in which the Mesozoic and Cenozoic sedimentary rocks are complexly folded and faulted. Between the Sierra Nevada and Coast Ranges is the San Joaquin Basin. When the basin first formed it was an inland sea between the two mountain ranges. Through time the Sierra Nevada volcanics and Coast Range sediments were eroded and filled the inland sea in what has become the San Joaquin Basin. This sediment included Monterey Formation turbidite sands that prograded across the deep floor of the southern basin.

**Figure 1: Location of Elk Hills Oil Field, San Joaquin Basin, California.**




At the surface, the EHOF presents as a large WNW-ESE trending anticlinal structure, approximately 17 miles long and over seven miles wide. With increasing depth, the structure sub-divides into three distinct anticlines (Figure 2), separated at depth by inactive high-angle reverse faults. The anticlines formed in the middle Miocene and are associated with uplift due to southern basin shortening from the San Andreas Fault (Callaway and Rennie Jr., 1991).

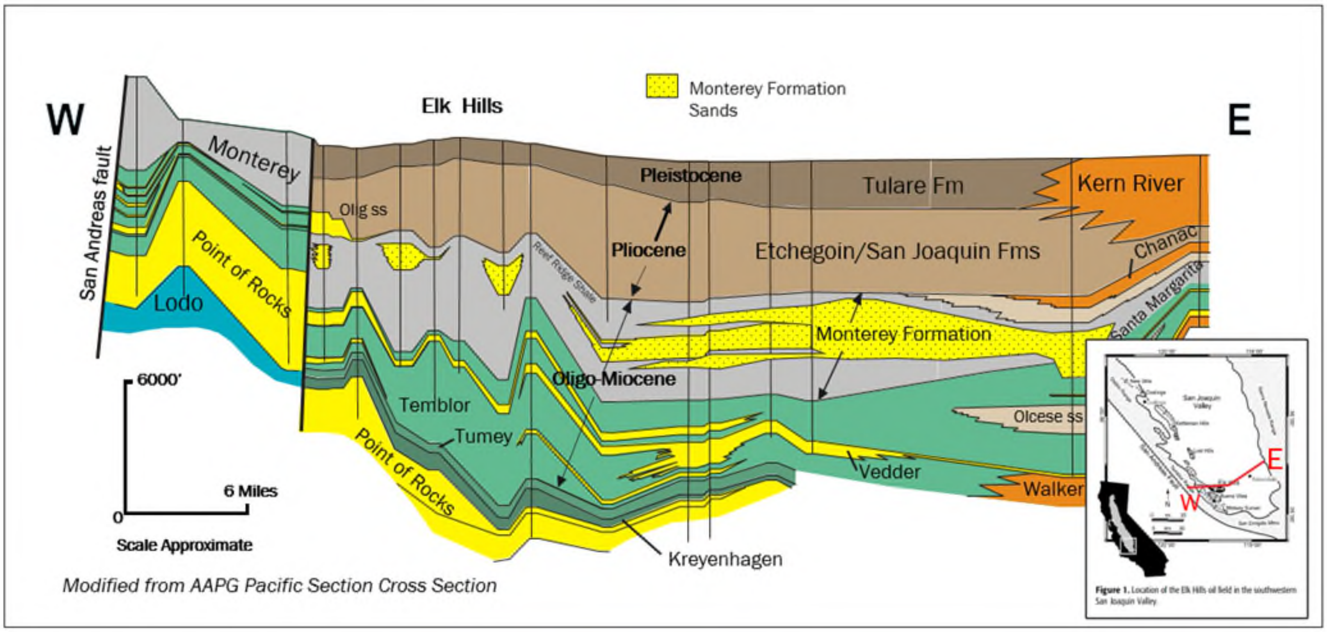
**Figure 2: The EHOF consists of the Northwest Stevens, 31S and 29R anticlines, with turbidite deposition occurring in fairways. The Monterey Formation A1-A2 CO2 sequestration reservoir is located in the Northwest Stevens anticline (Zumberge, 2005).**



Geological Sequence

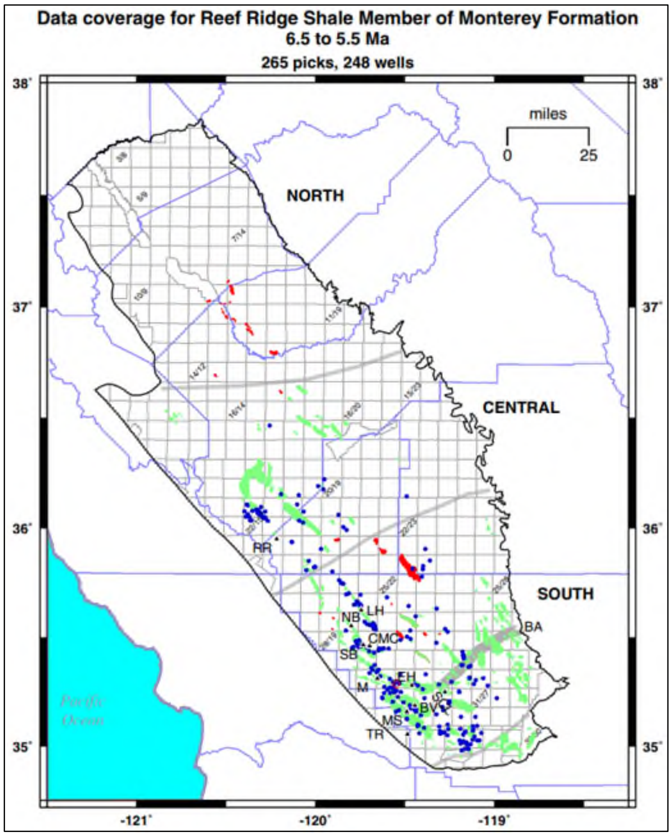
Figure 3 shows the stratigraphy of the EHOF. The two injection wells will inject $CO_2$ into the Miocene aged Monterey Formation A1-A2 at the Northwest Stevens anticline approximately 8,500 feet below the ground surface. This injection zone has a known reservoir capacity and injectivity as demonstrated by 40 years of oil and gas production and injection history.

**Figure 3: Cross-section across the southern San Joaquin Basin showing the lateral continuity of the major formations (Zumberge, 2005).**




Following its deposition, Monterey Formation sands and shales were buried under more than 1,000 feet of impermeable silty and sandy shale of the confining Reef Ridge Shale. The Reef Ridge Shale is present over the southern San Joaquin Basin (Figure 4) and serves as the primary confining layer for the Monterey Formation A1-A2 reservoir with low permeability, sufficient thickness, and regional continuity well beyond the area of review (AoR). Above the Reef Ridge Shale are several alternating sand-shale sequences of the Pliocene Etchegoin Formation and San Joaquin Formations, and Pleistocene Tulare Formation. These formations are laterally continuous across the San Joaquin Basin as highlighted in Figure 3.

**Figure 4: Reef Ridge Shale data coverage over the San Joaquin Basin (Hosford, 2007).**

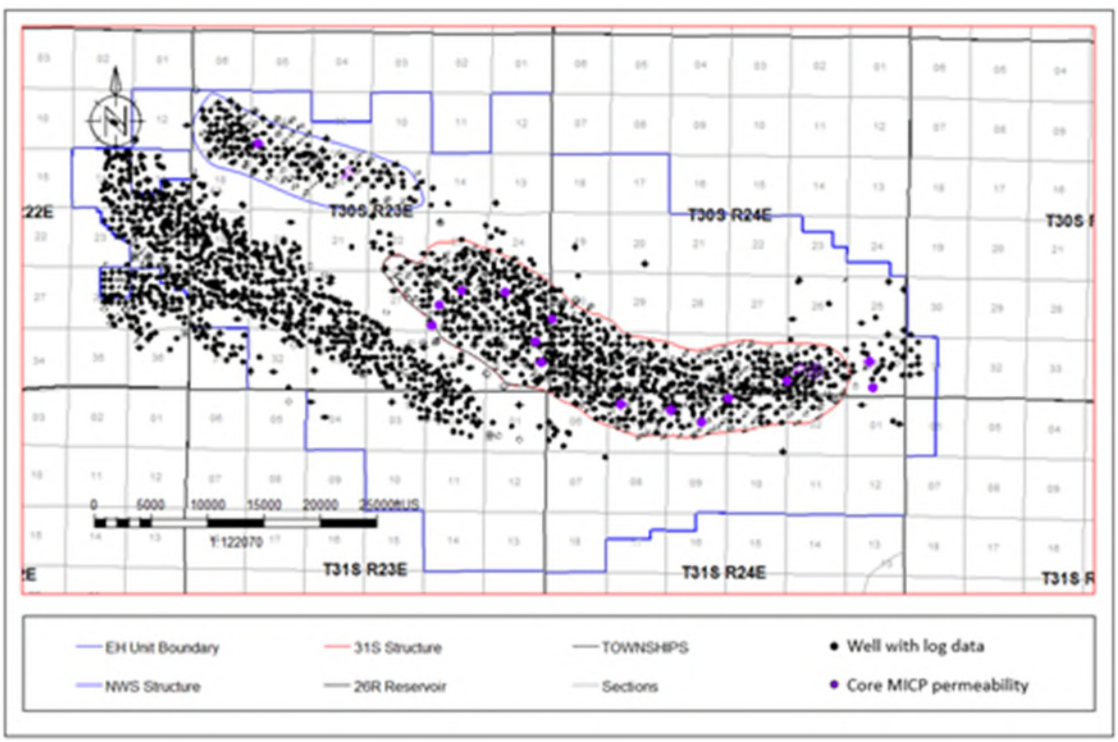


## *Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]*

Elk Hills Data

To date, more than 7,500 wells have been drilled to various depths within the EHOF (Figure 5), creating an extensive library of information compiled within a comprehensive database. The database consists of core, electric and geophysical logs, and reservoir performance data such as production, injection, and pressures. In addition to well data, a 3-D seismic survey was acquired over the EHOF in 2000. Seismic combined with well data defines the sequestration zone, confining layers, and the subsurface structure.

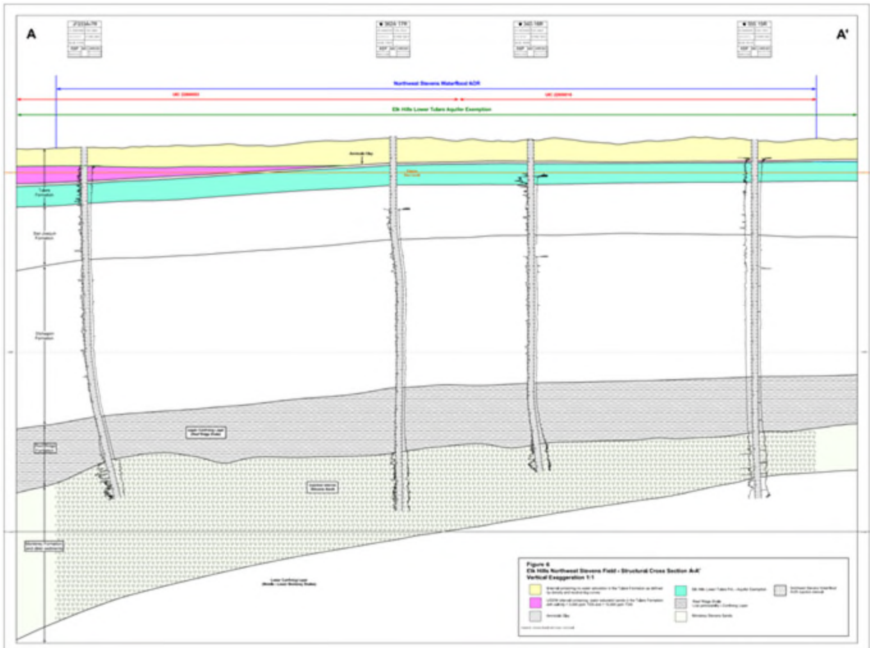
**Figure 5: Wells drilled in the EHOF that penetrate the confining Reef Ridge Shale. All wells shown have open-hole well logs. Wells with MICP core from the Monterey Formation are in purple.**




Elk Hills Stratigraphy

Major stratigraphic intervals include, from youngest to oldest, the Temblor Formation Reef Ridge Shale, Monterey Formation and Temblor Formation. This stratigraphy is shown in Figure 6 and discussed below. These formations are regionally continuous, with depositional environment affecting sand continuity and reservoir communication.

**Figure 6: Cross section showing stratigraphy, type wells and the lateral continuity of major formations in the Northwest Stevens anticline.**



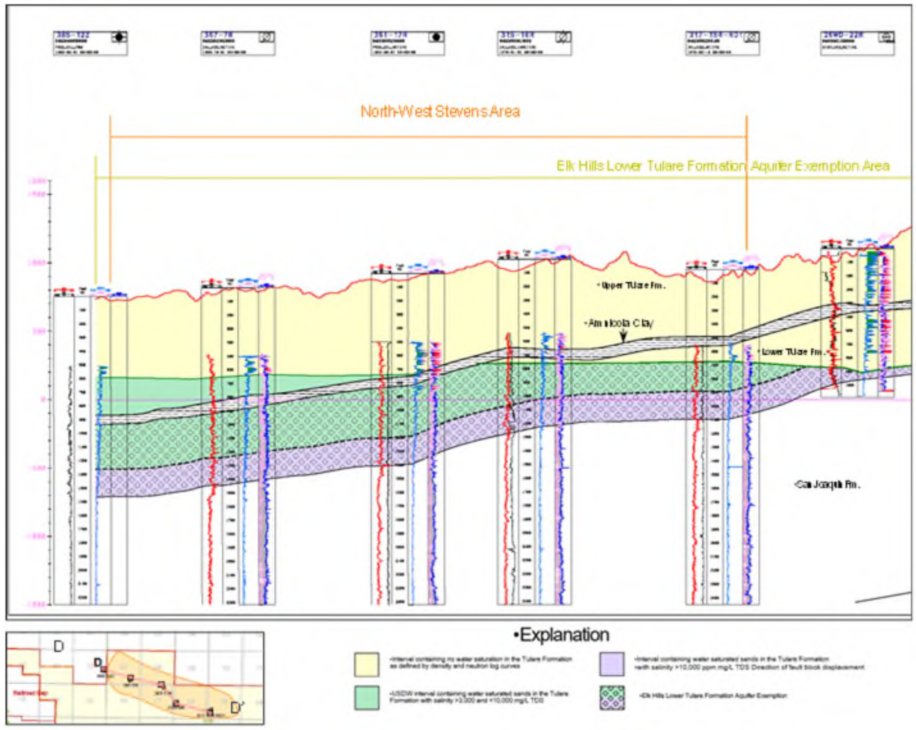
Tulare Formation

The Tulare Formation is a thick succession of nonmarine poorly consolidated sandstone, conglomerate, and claystone beds, which are exposed at intervals along the west border of the San Joaquin Valley. The Pleistocene aged Tulare Formation can be divided into the Upper Tulare and Lower Tulare members (Figure 7), separated by a continuous low permeability claystone (Amnicola Clay). The sandstone beds have 34 - 40% porosity, 1,410 - 8,150 mD permeability, and are up to 50 feet thick, separated by much thinner beds of siltstone and claystone.

The conformable base of the Tulare represents a facies transition from Tulare Formation nonmarine fluvial and alluvial sediments to the shallow marine siltstones and shales of the San Joaquin Formation (Maher et al., 1975). The upper Tulare Formation outcrops at the EHOF and can be overlain by undifferentiated quaternary strata.

The Upper Tulare contains 3,000 - 10,000 milligrams per liter (mg/l) total dissolved solids (TDS) water and is the only USDW in the AoR. The Lower Tulare formation was approved as an exempt aquifer in 2018.

**Figure 7: The Tulare Formation consists of the Upper Tulare USDW and Lower Tulare and is separated by the Amnicola Clay. The Lower Tulare is an exempt aquifer. The Upper Tulare USDW has formation water 3,000 - 10,000 mg/l TDS.**




San Joaquin Formation

The upper portion of the San Joaquin Formation consists mostly of shale, interbedded clayey siltstone, and silty sandstone. The sandstone is scattered through the interval and is thin, very fine to fine grained sand and silt. The upper contact of the formation with the Tulare Formation is marked in most places by a pronounced lithologic change upward from shale to poorly sorted feldspathic sandstone and conglomerate. In some places the lower beds of sandstone and conglomerate of the Tulare Formation interfinger with the San Joaquin beds. The lower San Joaquin Formation is comprised of consolidated to semi-consolidated sandstone, siltstone, and shale of marine origin with 28 - 45% porosity and 64 - 6,810 millidarcy (mD) permeability.

The lower San Joaquin Formation contains the Mya Gas Sands, lenticular sand bodies that are charged with gas and are encased in claystone. This depleted Mya gas reservoir would effectively dissipate any possible $CO_2$ leakage before it could reach the Upper Tulare USDW.

Etchegoin Formation

The marine deposited and Pliocene aged Etchegoin Formation is present in the subsurface across most of the southern San Joaquin Basin. At the EHOF, the formation is 1,500 - 4,000’ in depth and consists of a lower silty shale member and an upper sandy interval (Maher, 1975). The sand dominated sequences consist of multiple sands that are 10 feet in thickness, 29 – 37% porosity, 32 – 826 mD permeability and can contain oil. Between sand reservoirs are laterally continuous shales that are sealing and prevent hydraulic communication from above and below.

Reef Ridge Shale

Within the upper Miocene is the marine deposited siliceous Reef Ridge Shale, which is at 6,929-7,962 feet true vertical depth in the AoR. The Reef Ridge Shale is dominated by gray to grayish-black silty or sandy shale with rare silty and claybeds. At the EHOF the Reef Ridge Shale is continuous over the EHOF, ranges from 750 to 1,600 feet thick and has a permeability of less than 0.01 mD and 7% porosity.

The Reef Ridge directly overlies the Monterey Formation A1-A2 sequestration reservoir and has successfully contained oil and gas operations for over 40 years, and original oil and gas deposits for millions of years.

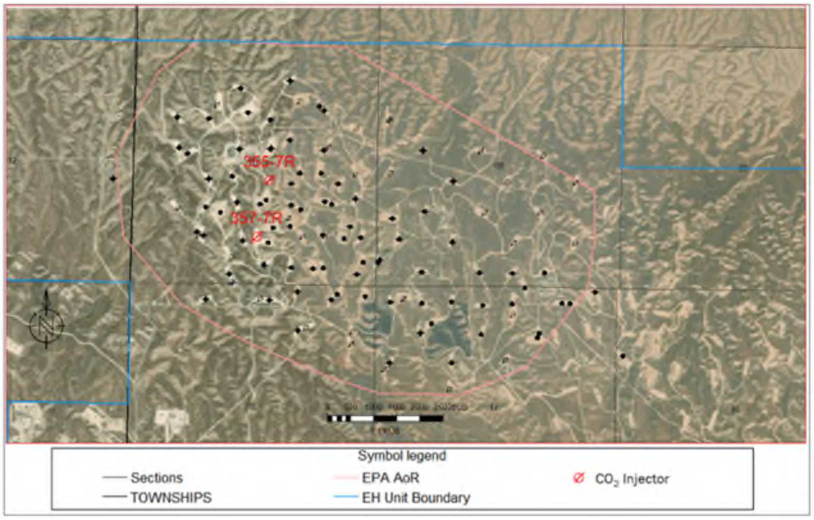
Monterey Formation

The Monterey Formation A1-A2 sequestration zone is approximately 8,500 feet deep and produces from turbidite sands. Turbidite deposited sands are interbedded with and bound above and below by siliceous shale. Sand porosity and permeability averages 16% and 60 mD, respectively.

The Monterey Formation A1-A2 sands were deposited in two coalescing turbidite channels which were influenced by the growing Elk Hills structure at the time of deposition. In Elk Hills the structure occurs synchronously with deposition. Although the Monterey Formation was deposited over the entire San Joaquin Basin, sands are sourced from the Sierra Nevada, San Emigdio and Coast Range highlands with deposition occurring in fairways (Figure 2). This depositional framework minimizes lateral communication of the Monterey Formation outside the EHOF. Figure 2 shows the orientation and depositional fairways for these channels in the Northwest Stevens anticline. The sands were largely aggregational with minimal erosive deposition.

The reservoir is continuous across the AoR and sands pinch-out on the channel edges. The Monterey Formation A1-A2 sequestration reservoir has minimal connection outside the AoR, creating a reservoir with no connection to regional saline aquifers. Within the AoR there is no evidence of faults that transect the Monterey Formation or penetrate the Reef Ridge confining layer.

**Figure 8: AoR and injection well location map for Elk Hills A1-A2 project. The injection wells, 355-7R and 357-7R are 1,250 feet apart. Also shown are the wells that penetrate the confining Reef Ridge Shale.**

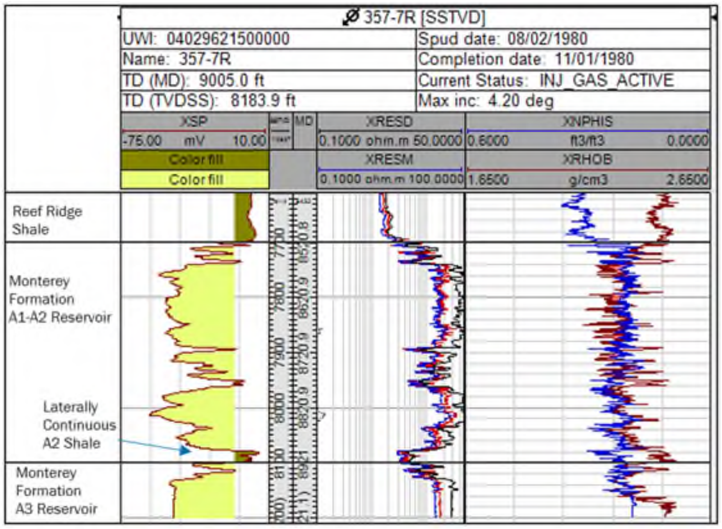



Underlying Monterey Formation A3-A11:

Underlying the Monterey A1-A2 Formation is the Monterey Formation A3-A11 reservoir. This stratigraphic package is not in communication with the A1-A2, as indicated by the following:

1. The two packages have been developed separately. The A1-A2 reservoir was previously pressure supported by gas injection (175 billion cubic feet injected) while the A3-A11 reservoir is currently pressure supported by waterflood (449 million barrels of water injected).
2. The Monterey Formation A1-A2 reservoir is at 200-300 PSI and the A3-A11 reservoir is much higher at approximately 1,700 PSI. This pressure differential is maintained due to hydraulic confinement between the two reservoirs.
3. The laterally continuous A2 shale separates the reservoirs (Figure 9). This shale is greater than 20 feet thick across the AoR and prevents communication between the Monterey Formation A1-A2 reservoir and the Monterey Formation A3-A11 reservoir.

**Figure 9: 357-7R injector showing the Monterey Formation A1-A2 reservoir and the laterally continuous A2 Shale above the Monterey Formation A3-A11 reservoir.**




CTV will monitor the Monterey Formation A3-A11 reservoir and wellbores for $CO_2$ migration. Waterflood producers will be monitored via fluid sampling once per quarter for changes in composition. In addition, Monterey Formation A3-A11 waterflood injectors will have mechanical integrity tests (MIT) and standard annular pressure tests (SAPT) to ensure internal and external mechanical integrity. This monitoring will be discussed in more detail within the Testing and Monitoring Plan. Additionally, due to its waterflood infrastructure and high reservoir pressure, the A3-A6 reservoir is considered a viable future target for $CO_2$ miscible enhanced oil recovery.

Summary:

The Northwest Stevens Monterey depositional framework and sand continuity have been established by static data that includes open-hole well logs and core as well as three dimensional seismic. Augmenting the static data is the dynamic data, which includes production, injection and pressure data gathered over the 40-year development history. Both datasets support the geological framework establishing sand continuity and as well as confinement by the Reef Ridge Shale.

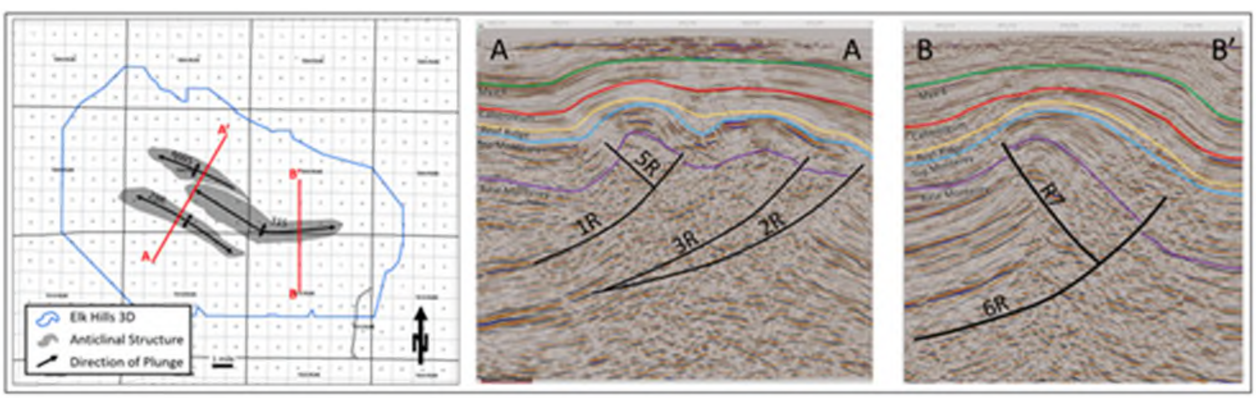
## *Faults and Fractures [40 CFR 146.82(a)(3)(ii)]*

Overview

The 31S and NWS anticlines formed bathymetric highpoints on the deep inland marine surface (seafloor), affecting geometry and lithology of the contemporaneously deposited turbidite sands and muds generated as subaqueous turbidite flows. Mid-Miocene thrust faults accompanying the development of the anticlines separate each structure at depth.

Initial interpretations of the three-dimensional (3D) seismic survey were based on a conventional pre-stack time migration volume. In 2019 the 3D seismic survey was re-processed using enhanced computing and statistics to generate a more robust velocity model. This updated processing to enhance the velocity model is referred to as tomography. The more accurate migration velocities used in the updated seismic volume allows a more focused structural image and clearer seismic reflections around tight folds and faults. The illustration in Figure 10 displays the location and extent of faults that helped to form the EHOF anticlines. Offsetting the NWS anticlines are high angle reverse faults that are oriented NW-SE. These inactive faults penetrate the lowest portions of the Monterey Formation but there is no data supporting transection of the Monterey Formation nor penetration into the lower Reef Ridge Shale.

**Figure 10: EHOF Showing location of NWS and 31S anticlines with 3-D seismic boundary and line of cross sections. (Right) Cross Section A-A' and B-B' showing structure of EHOF anticlines with reverse faults.**




Fluid Confinement

Extensive well data, 3D seismic and operating experience, that includes the injection of water and gas, supports reservoir confinement of the $CO_2$ injectate in the Monterey Formation A1-A2 sands:

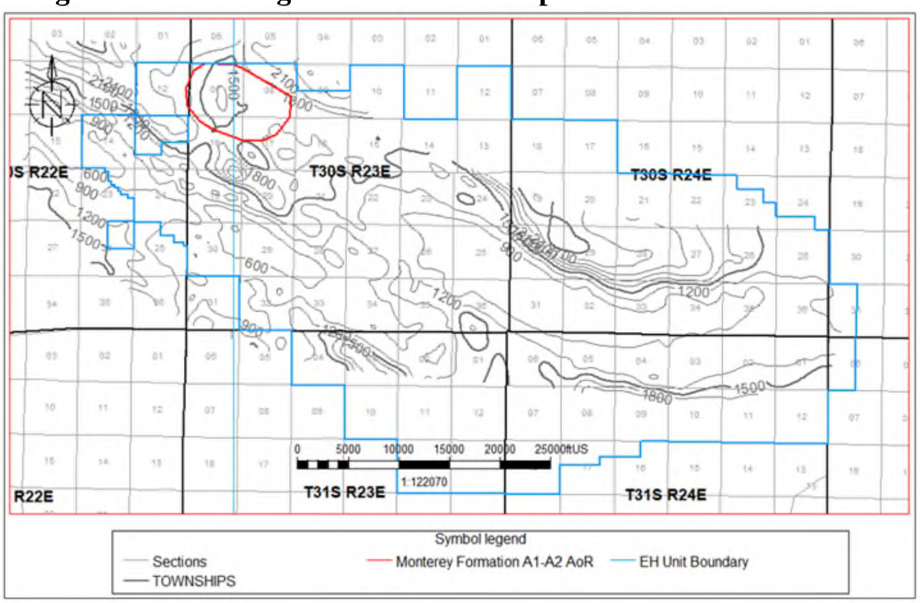
1. There are no faults that extend into the confining Reef Ridge Shale.

2. Extensive water and gas injection operations validate the reservoir characterization and demonstrate confinement within zones.
3. A pressure differential exists above and below the Reef Ridge confining interval, confirming lack of communication.
4. Geochemical analysis of reservoirs within the EHOF also confirms compartmentalization through several million years and effectiveness of the Reef Ridge Shale to contain the $CO_2$ injectate.

1. Seismic Control

The Reef Ridge is a thick continuous shale over the San Joaquin Basin. In the EHOF the thickness averages 1,100 feet (Figure 11) and is well resolved within seismic. Analysis of the three-dimensional seismic and well data provides no evidence that the faults either transect the Monterey Formation or penetrate the confining Reef Ridge Shale.

**Figure 11: Reef Ridge Shale isochore map for the Elk Hills Oil Field.**




2. Waterflooding and Gas Injection

Waterflooding and gas injection for the purpose of pressure support is conducted under a set of Class II UIC permits issued by CalGEM and reviewed by the State Water Resources Control Board. To date, more than five million barrels of water and 175 billion cubic feet of gas have been injected into the Monterey Formation A1-A2 sands. There has been no evidence of water or gas migrating out of the reservoir or through the Reef Ridge Shale. Historic waterflood and gas injection results provide clear evidence that the planned sequestration zone is vertically and aerially confined.

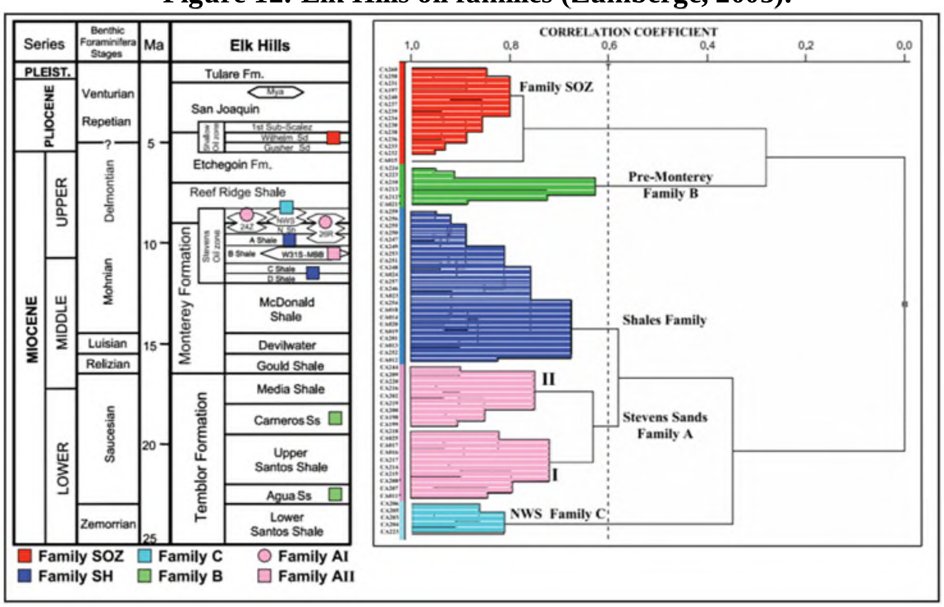
3. Pressure Differentials

The Monterey Formation A1-A2 sequestration zone average current pressure is approximately 230 PSI. Overlying the sequestration zone, and separated by the confining Reef Ridge Shale, the Etchegoin Formation aquifer sands are at a much higher pressure of 1,500 PSI (0.43 PSI/foot gradient at 3,600 feet depth). This pressure differential of 1,300 PSI between the overlying Etchegoin Formation and Monterey Formation is maintained because the Reef Ridge is sealing and there are no transmissive features.

4. Geochemical Analysis

Geochemical data from 66 oil samples also confirms there is vertical isolation between the Monterey Formation and the overlying formations (Zumberge, 2005). Analysis revealed five distinct oil families (Figure 12) sourced from the Miocene Monterey Formation and tied to stratigraphic intervals. The differences between the distinct geochemical compositions of the Monterey Formation and overlying formations hydrocarbons suggests "minimal up-section, [and] cross stratigraphic migration". The authors conclude that the hydrocarbons present in the overlying formations are from "another Monterey source facies (perhaps the youngest) with charging of Pliocene reservoirs" and not the result of upward movement from the older Miocene reservoirs.

**Figure 12: Elk Hills oil families (Zumberge, 2005).**



## *Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]*

### Depth and Thickness

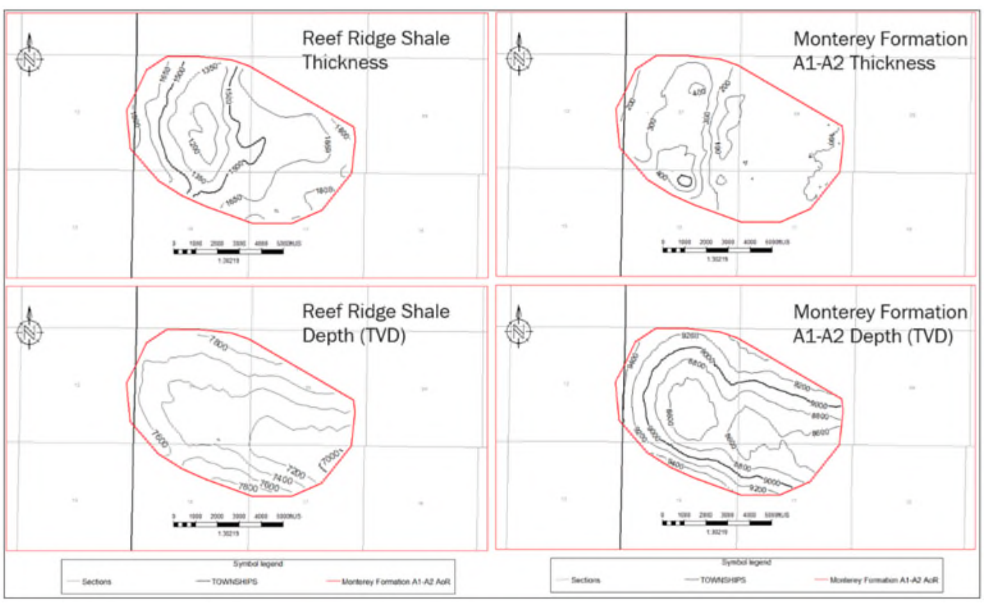
Depths and thickness of the Monterey Formation A1-A2 reservoir and Reef Ridge Confining Shale (Table 1) are determined by structural and isopach maps (Figure 13) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

1. Reef Ridge and Monterey Formation structural variability due to the Elk Hills anticlinal structure.
2. Reef Ridge Shale thickness variability due to deposition of the Monterey Formation sands. In the AoR, the Reef Ridge Shale minimum thickness corresponds to a high in Monterey Formation A1-A2 sand thickness.
3. Monterey Formation A1-A2 thickness variability is from pinch-out of the reservoir on the structure.

**Table 1: Reef Ridge Shale and Monterey Formation A1-A2 thickness and depth for the AoR.**

| Zone | Property | Low | High | Mean |
|---|---|---|---|---|
| Confining Zone<br>Reef Ridge Shale | Thickness (feet) | 1,122 | 1,892 | 1,555 |
| | Depth (feet TVD) | 6,929 | 7,962 | 7,441 |
| Reservoir<br>Monterey Formation A1-A2 Sand | Thickness (feet) | 27 | 548 | 204 |
| | Depth (feet TVD) | 8,403 | 9,598 | 5,907 |

**Figure 13: Reef Ridge Shale and Monterey Formation A1-A2 thickness and depth maps.**



Variability in the thickness and depth of the either the Reef Ridge Shale or the Monterey Formation A1-A2 sands will not impact confinement. CTV will utilize thickness and depths shown when determining operating parameters and assessing project geomechanics.

### Mineralogy

Monterey Formation A1-A2:

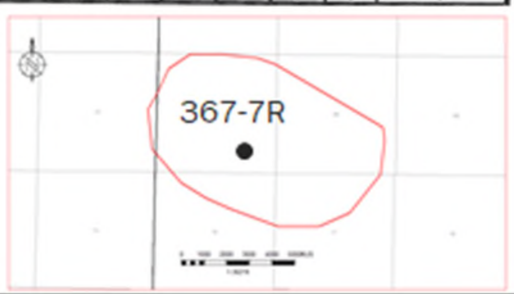
X-ray diffraction data has been compiled and compared from 9 wells with a total of 108 data points. Clay speciation has been found to be consistent throughout the AoR. Offset well 367-7R (Figure 14) provides an example of the mineralogy for the reservoir interval in 357-7R. Clean reservoir sand intervals have an average of 43% quartz, 38% potassium feldspar, albite and oligoclase as well as 7% total clay.

**Figure 14: Monterey Formation A1-A2 sand mineralogy from well 367-7R.**

| DEPTH | GDI | SAMP. WT | QTZ | CHRT | OP-A | OP-CT | ALB | OLIG | ANDE | KSPAR | CALC | DOLO | PYR | KAOL | CHLOR | ILL/SMEC |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8551.9 | 2.62 | 8.34 | 30 | 13 | 0 | 0 | 17 | 0 | 2 | 21 | 2 | 0 | 1 | 0 | 0 | 14 |
| 8552.0 | 2.62 | 9.41 | 28 | 13 | 0 | 0 | 14 | 10 | 0 | 15 | 3 | 0 | 0 | 0 | 3 | 14 |
| 8554.1 | 2.62 | 10.73 | 45 | 0 | 0 | 0 | 19 | 0 | 2 | 20 | 4 | 0 | 0 | 0 | 0 | 10 |
| 8560.6 | 2.62 | 11.57 | 44 | 0 | 0 | 0 | 15 | 11 | 0 | 17 | 5 | 0 | 0 | 2 | 0 | 6 |
| 8570.0 | 2.62 | 8.32 | 43 | 0 | 0 | 0 | 17 | 8 | 4 | 17 | 3 | 0 | 0 | 0 | 0 | 8 |
| 8593.0 | 2.62 | 14.88 | 45 | 0 | 0 | 0 | 15 | 11 | 0 | 18 | 4 | 0 | 0 | 0 | 0 | 7 |
| 8608.9 | 2.60 | 18.83 | 21 | 21 | 0 | 0 | 15 | 0 | 10 | 14 | 2 | 0 | 0 | 0 | 0 | 17 |
| 8634.9 | 2.62 | 21.65 | 44 | 0 | 0 | 0 | 16 | 13 | 1 | 17 | 3 | 0 | 0 | 0 | 0 | 6 |
| 8648.6 | 2.62 | 14.16 | 47 | 0 | 0 | 0 | 18 | 3 | 5 | 19 | 3 | 0 | 0 | 0 | 0 | 5 |
| 8649.2 | 2.62 | 15.56 | 49 | 0 | 0 | 0 | 18 | 0 | 4 | 18 | 3 | 0 | 0 | 2 | 0 | 6 |
| 8649.8 | 2.62 | 8.73 | 50 | 0 | 0 | 0 | 17 | 0 | 4 | 17 | 1 | 2 | 0 | 3 | 0 | 6 |
| 8650.9 | 2.62 | 11.24 | 45 | 0 | 0 | 0 | 14 | 9 | 4 | 17 | 2 | 1 | 0 | 2 | 0 | 6 |
| 8651.8 | 2.62 | 8.75 | 46 | 0 | 0 | 0 | 16 | 0 | 6 | 19 | 3 | 0 | 0 | 0 | 0 | 10 |
| 8656.0 | 2.63 | 23.81 | 38 | 0 | 0 | 0 | 14 | 10 | 4 | 14 | 12 | 2 | 0 | 0 | 0 | 6 |
| 8702.6 | 2.61 | 10.56 | 40 | 13 | 0 | 0 | 15 | 0 | 5 | 18 | 2 | 0 | 0 | 0 | 0 | 7 |

GDI = GRAIN DENSITY INDEX
SAMP. WT = WEIGHT OF FRESH SAMPLE CRUSHED FOR ANALYSIS
QTZ = QUARTZ
CHRT = CHERT
OP-A = OPAL-A
OP-CT = OPAL-CT
ALB = ALBITE
OLIG = OLIGOCLASE

ANDE = ANDESINE
KSPAR = POTASSIUM FELDSPAR
CALC = CALCITE
DOLO = DOLOMITE
PYR = PYRITE
KAOL = KAOLINITE
CHLOR = CHLORITE
ILL/SMEC = ILLITE + SMECTITE

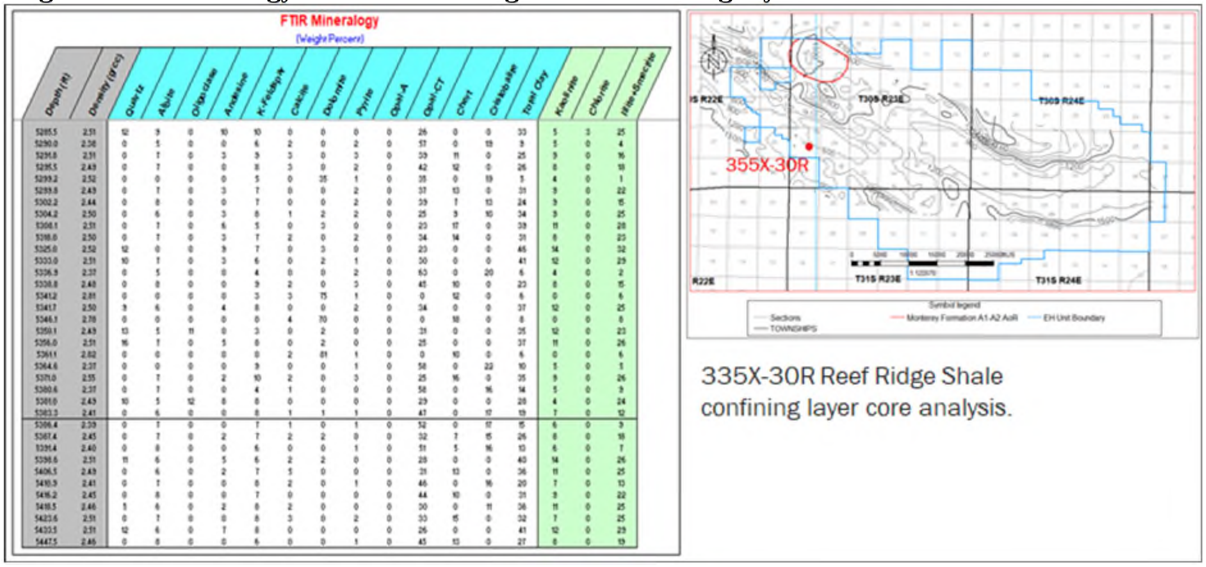



Reef Ridge Shale:

Fourier Transform Infrared Spectroscopy is used to determine mineralogy of the confining zone from 36 points in one well (Figure 15). In the high clay intervals, the confining zone has an average of 29.5% total clay, 3.7% quartz, 14.5% potassium feldspar, albite and oligoclase as well as 47.1% silica polymorphs (Opal-CT, chert and Cristobalite).

This well is not located in the AoR but is representative of the marine Reef Ridge Shale in the AOR due to the depositional continuity of the unit, proximity to the project and consistency of facies and properties.

**Figure 15: Mineralogy for the Reef Ridge Shale confining layer from well 355X-30R core data.**



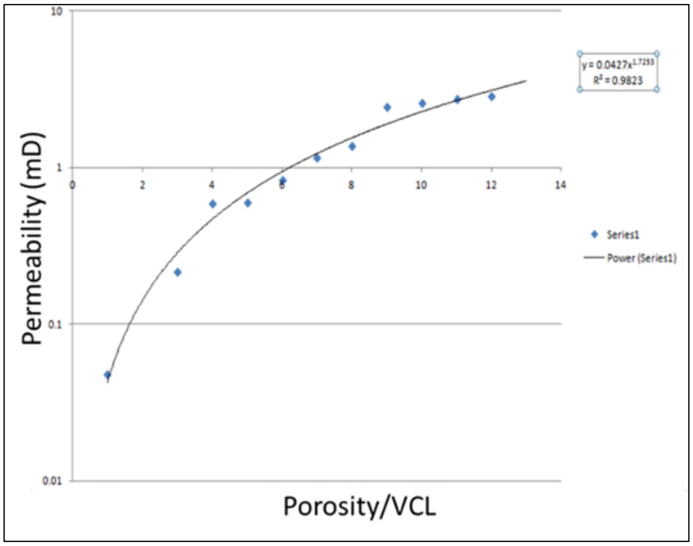

## Porosity and Permeability

Monterey Formation A1-A2:

Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, resistivity as well as neutron porosity and bulk density.

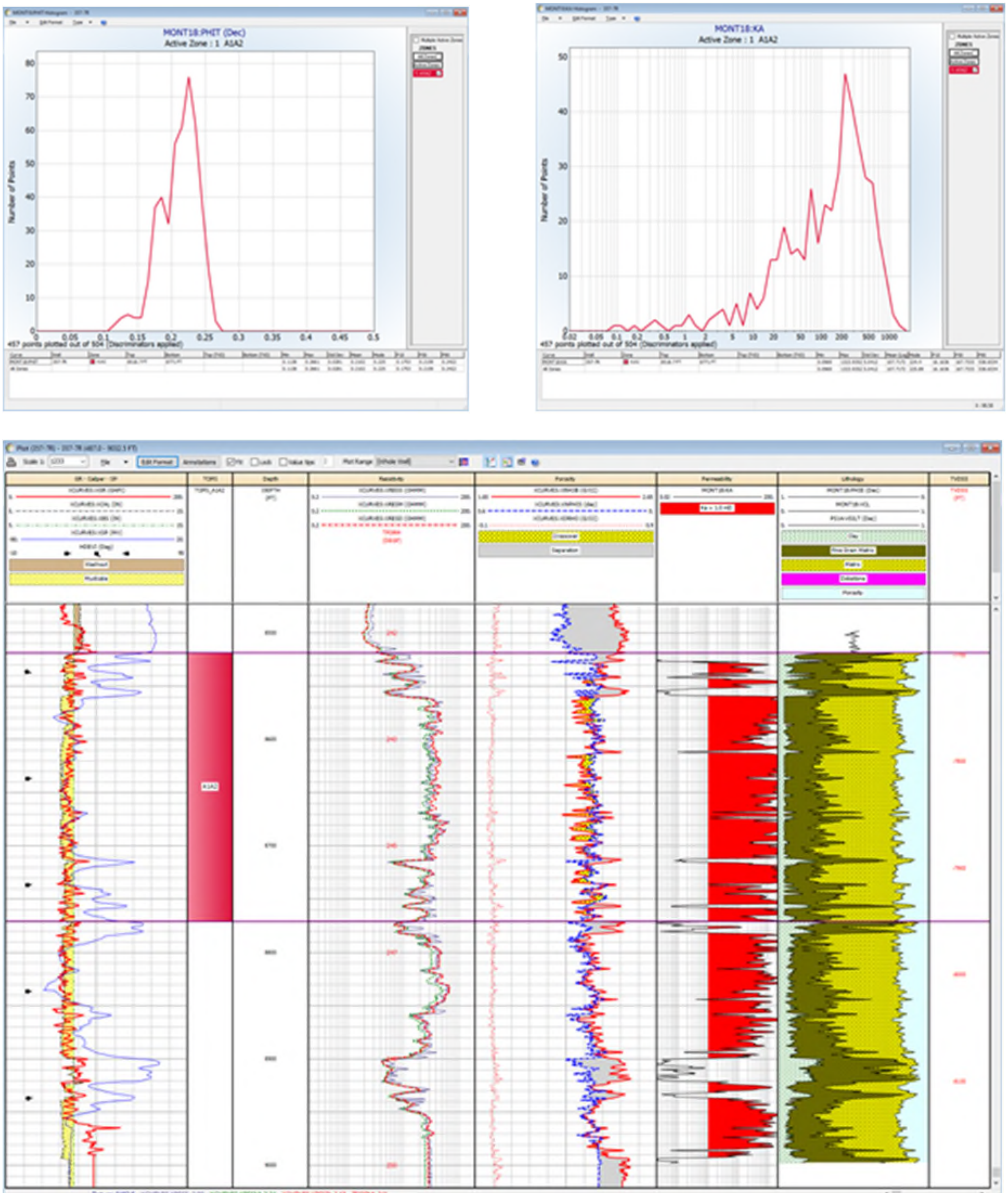
> Formation porosity is determined from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and porosity data.
>
> Volume of clay is determined by neutron-density separation and is calibrated to core data.
>
> Log-derived permeability is determined by applying a core-based transform that utilizes mercury injection capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy. Core data from 13 wells with 175 data points were used to calibrate log porosity and to develop a permeability transform. An example of the transform from core data is illustrated in Figure 16 below.

**Figure 16: Permeability function developed based on mercury injection capitally pressure data and calculated from log derived porosity and clay volume.**




In the example below for the Monterey Formation A1-A2 sands, the porosity ranges from 11% - 27% with a mean of 21%. The permeability ranges from 0.1 mD - 1300 mD with a log mean of 108 mD (Figure 17).

**Figure 17: Porosity and permeability for well 357-7R, showing the distribution and the input and output log curves.**



Reef Ridge Shale:

The average porosity of the confining zone is 7.7% based on 11 mercury injection capillary pressure core data points.

The average permeability of the confining zone is 0.0084mD based on 11 mercury injection capillary pressure core data points in well 355X-30R (Table 2).

**Table 2: Permeability and porosity for the Reef Ridge Shale in the 355X-30R well from mercury injection capillary pressure data.**

| Sample | Depth (ft) | Porosity (dec) | Permeability (mD) |
|---|---|---|---|
| TEST1 | 5290 | 0.0586 | 0.00007 |
| TEST2 | 5299.2 | 0.0351 | 0.00003 |
| TEST3 | 5338.8 | 0.0922 | 0.0002 |
| TEST4 | 5361.1 | 0.137 | 0.0917 |
| TEST5 | 5364.4 | 0.0536 | 0.00006 |
| TEST6 | 5380.6 | 0.0611 | 0.00007 |
| TEST7 | 5383.3 | 0.0794 | 0.00012 |
| TEST8 | 5386.4 | 0.0541 | 0.00006 |
| TEST9 | 5391.4 | 0.102 | 0.0002 |
| TEST10 | 5416.2 | 0.0894 | 0.0002 |
| TEST11 | 5447.5 | 0.0806 | 0.00011 |
| Average | 5368.99 | 0.07665 | 0.00844 |

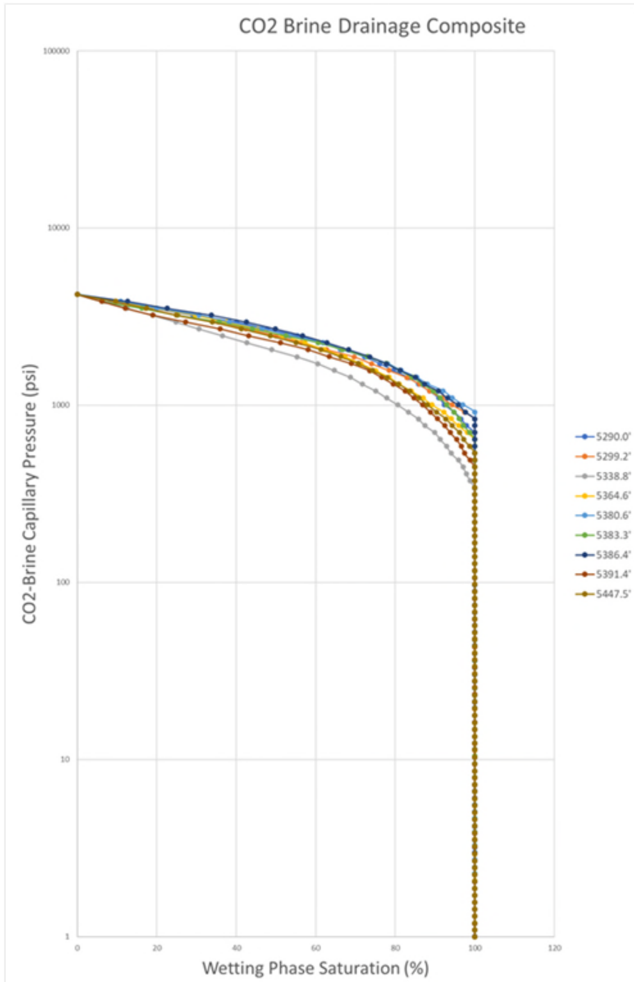
Reef Ridge Shale Capillary Pressure:

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

The capillary pressure of the Reef Ridge confining zone is 4,220 psi in a $CO_2$-brine system based on 11 mercury injection capillary pressure core data points in one well (Figure 18). The capillary pressure was determined by applying $CO_2$-brine corrections to air-mercury test data. An interfacial tension of 480 dynes/cm was used for air-mercury and 30 dynes/cm was used to convert to $CO_2$-

brine. The cosine of contact angles of 0.766 and 0.866 degrees were also used for air-mercury and $CO_2$-brine, respectively.

**Figure 18: Capillary pressure versus wetting phase saturation for core data from well 355X-30R.**



## *Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]*

Reef Ridge Ductility:

Over 40 years of water and gas injection have been confined by the shale in AoR and the San Joaquin Basin. Ductility and the unconfined compressive strength (UCS) of the Reef Ridge Shale are two properties used to describe geomechanical behavior. Ductility refers to how much the Reef Ridge Shale can be distorted before it fractures, while the UCS is a reference to the resistance of the Reef Ridge to distortion or fracture. Ductility decreases as compressive strength increases. Within the AoR, 18 wells had compressional sonic data over the Reef Ridge Shale to calculate ductility and UCS, comprising 59,214 individual logging data points.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (UCS) vs. an empirically derived UCS for a normally consolidated rock ($UCS_{NC}$).

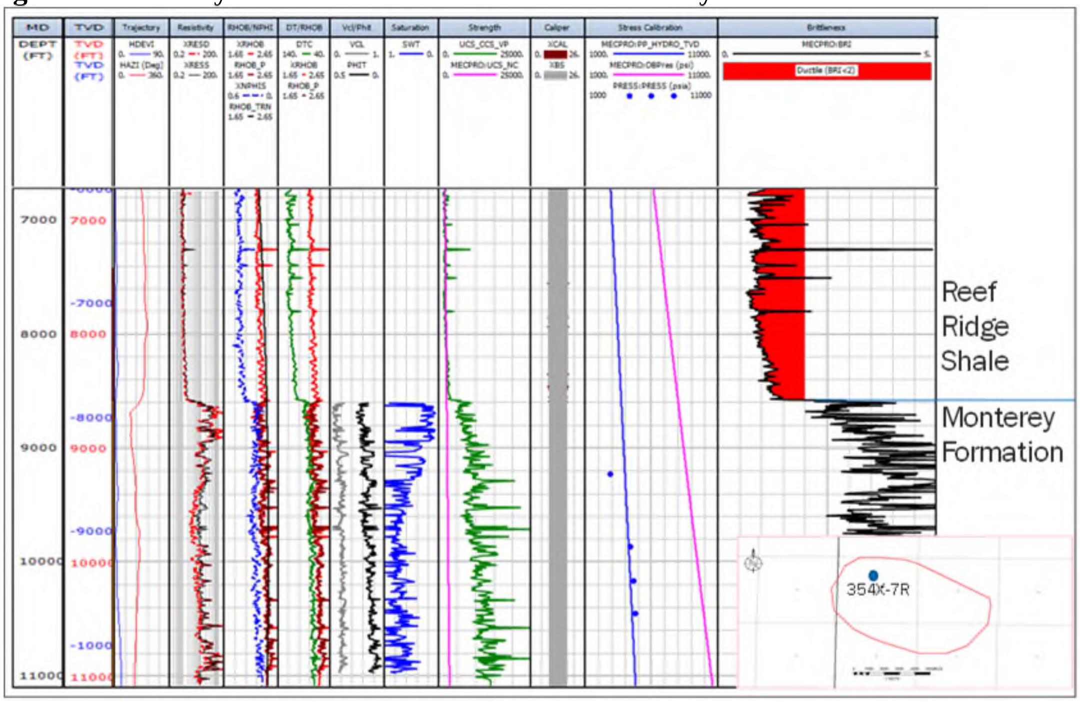
$$UCS_{NC} = 0.5\sigma'$$

$$\sigma' = OB_{Pres} - P_P$$

$$BRI = \frac{UCS}{UCS_{NC}}$$

An example calculation for the well 354X-7R is shown below (Figure 19). UCS_CCS_VP is the UCS based on the compressional velocity, MECPRO:UCS_NC is the UCS for a normally consolidated rock, and MECPRO:BRI is the calculated brittleness using this method. Ductility less than two is shaded red.

**Figure 19: Unconfined compressive strength and ductility calculations for well 354X-7R. The Reef Ridge Shale ductility is less than two and will be sufficiently ductile to anneal discontinuities.**




At the Reef Ridge Shale and Monterey Formation interface, the brittleness calculation drops to a value less than two. If the value of BRI is less than 2, empirical observation shows that the risk of embrittlement is lessened, and the confining layer is sufficiently ductile to anneal discontinuities. This confirms that the Reef Ridge is a ductile confining layer.

> The average ductility of the confining zone based on the mean value from 18 wells is 1.24.
>
> The average rock strength of the confining zone, as determined by the log derived UCS from the BRI calculations, is 2,452 psi.

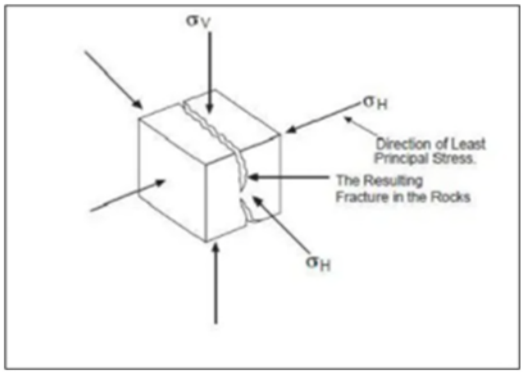
As a result of the Reef Ridge Shale ductility, there are no fractures that will act as conduits for fluid migration from the Monterey Formation A1-A2 reservoir. This conclusion is supported by the following:

1. Extensive water and gas injection within the Monterey Formation confined by the Reef Ridge Shale within the AoR, the Greater Elk Hills Oil Field area and the San Joaquin Basin.
2. Prior to discovery, the Reef Ridge Shale provided seal to the underlying gas and oil reservoirs of the Monterey Formation for several million years.

Stress Field:

The stress of a rock can be expressed as three principal stresses. Formation fracturing will occur when the pore pressure exceeds the least of the stresses. in this circumstance, fractures will propagate in the direction perpendicular to the least principal stress (Figure 20).

**Figure 20: Stress diagram showing the three principal stresses and the fracturing that will occur perpendicular to the minimum principal stress**.




Elk Hills stresses have been studied in depth utilizing the large quantity of data recorded and available on fracture gradients and borehole breakout. Figure 21 shows that the maximum principal stress (SHmax) in the Elk Hills area is largely oriented northeast – southwest.

**Figure 21: Map showing the SHmax stress orientations in the Southern San Joaquin Basin (Castillo, 1997).**

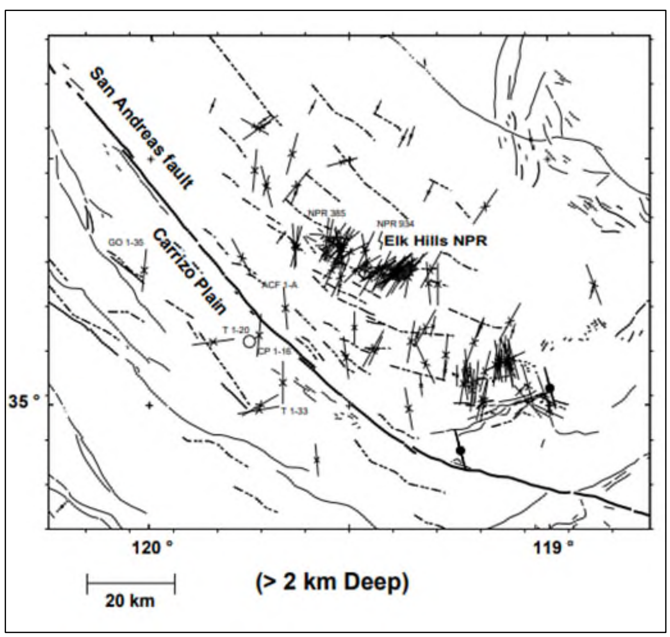


Table 3 shows the horizontal fracture gradients for the Reef Ridge Shale and the Monterey Formation A1-A2 reservoir.

**Table 3: Pressure gradients and pressures for the Monterey Formation A1-A2 reservoir and the Reef Ridge Shale.**

| Stress | Reef Ridge Shale Confining Layer (374A-7R-RD1) | Monterey Formation A1-A2 Reservoir (372-7R-RD1) |
|---|---|---|
| Pore Pressure Gradient (PSI/foot) | 0.433 | 0.2 |
| Overburden Gradient (PSI/foot) | 0.93 | 0.94 |
| Minimum Horizontal Stress Gradient (PSI/foot) | 0.73 | 0.97 |

## Geomechanical Modeling

Overview:

A finite element geomechanics module, GEOMECH, coupled with Computer Modeling Group's (CMG) equation of state compositional reservoir simulator (GEM), was used to model failure of the Reef Ridge Shale due to increasing pressure in the underlying reservoir by $CO_2$ injection. A modified Barton-Bandis model can be used to allow $CO_2$ to escape from the storage reservoir through the cap rock to overburden layers. The location and direction of fractures in a grid block are determined via normal fracture effective stress computed from the geomechanics module.

A generic two-dimensional model was constructed to represent the reservoir, confining layer, and overburden formations. $CO_2$ is injected through an injector located at the center of the X-Z plane and perforated throughout the reservoir. Increasing pressure in the reservoir is expected to push up and bend the overlying cap rock to create a tensile stress around the high-pressure region. As gas continues to be injected, the normal effective stress in the cap rock is expected to continually decrease. When the cap rock reaches a threshold value, defined as zero in this model, a crack will appear in the cap rock and the Barton-Bandis model will allow $CO_2$ to leak from the storage reservoir.

Results:

Failure pressures for the four scenarios are given in Table 4. The value for the reduced injection case was extrapolated from the pressure at a stress of about 10 PSI These results suggest that the Reef Ridge Shale can tolerate a pressure at the base of 7,500 PSI or more without failure.

**Table 4: Geomechanical modeling results for four scenarios.**

| GEOMECHANICAL SCENARIO RESULTS | |
|---|---|
| **SCENARIO** | **FAILURE PRESSURE, PSI** |
| BASE CASE | 8,306 |
| REDUCED YOUNG'S MODULUS | 8,388 |
| REDUCED INJECTION RATE | 8,340 |
| THINNER CAP ROCK | 7,600 |

Description:

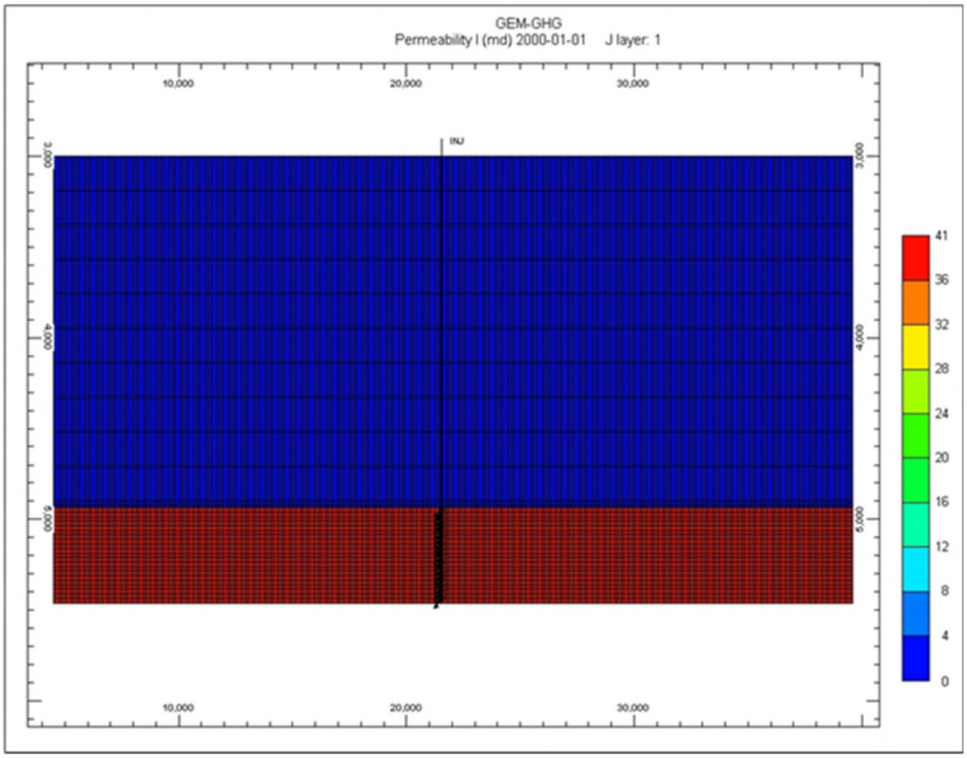
A 2-D cross-section model with 411 grid blocks in the X-direction and 33 grid blocks in the Z-direction was built encompassing a length of 43,100 feet and a thickness of 2,460 feet. This model is shown in Figure 22.

In the base model, the cap rock is 1,935 feet thick with a Young's modulus of 9E05 psi and a Poisson's ratio of 0.23. The reservoir is 525 feet thick with a Young's modulus of 7.25E05 and a Poisson's ratio of 0.25. Horizontal permeability is 1e-07 md in the cap rock and 40.5 md in the reservoir. The vertical to horizontal permeability ratio is 0.25. A constant porosity of 0.25 is used in all zones.

The reservoir is constrained at the bottom but allowed to move at the top and sides. The horizontal direction unconstrained boundary is used to cope with open regions on both the left and right of the modeled portion of the reservoir.

The injector was constrained to inject 30 million cubic feet per day of $CO_2$ with a maximum injection pressure of 10,000 PSI.

**Figure 22: Geomechanics Model.**

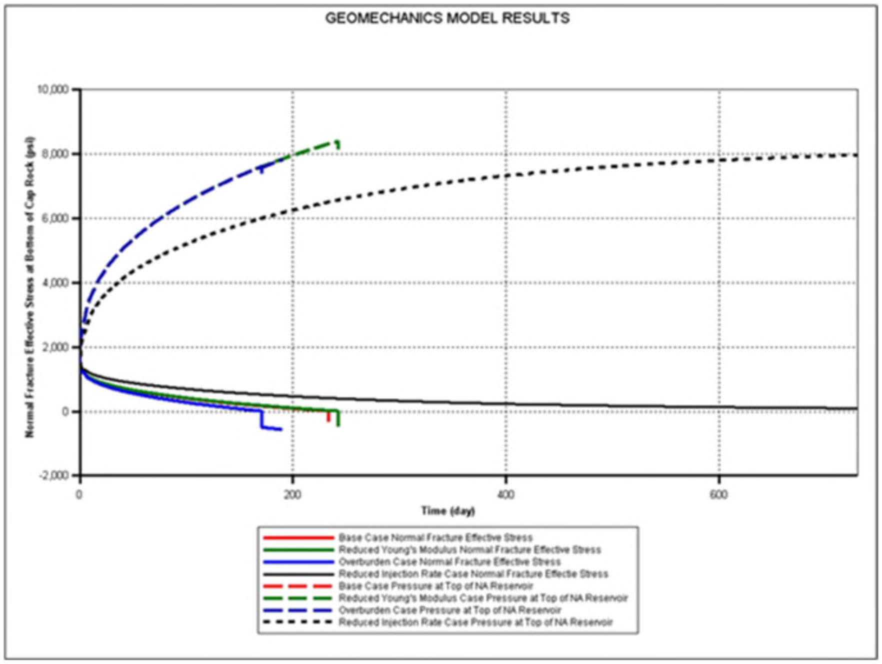



Scenarios Modeled:

Four scenarios were modeled in this study. In the base case, the cap rock has a Young's modulus of 9E05 PSI. To model uncertainty in the cap rock Young's modulus, a second case was run with a value of 8E05 PSI. In the third case, the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet. In the fourth case, sensitivity to injection rate was studied by reducing the injection rate to 20 million cubic feet per day.

Figure 23 gives the change in the normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. The failure pressure is defined as the value at which the effective stress is zero. In the reduced injection rate case the stress stopped decreasing at about 10 PSI, due to $CO_2$ bleeding into the cap rock despite the very low vertical permeability.

**Figure 23: Normal Fracture Stress and Pressure for Geomechanics Cases.**



## *Seismic History [40 CFR 146.82(a)(3)(v)]*

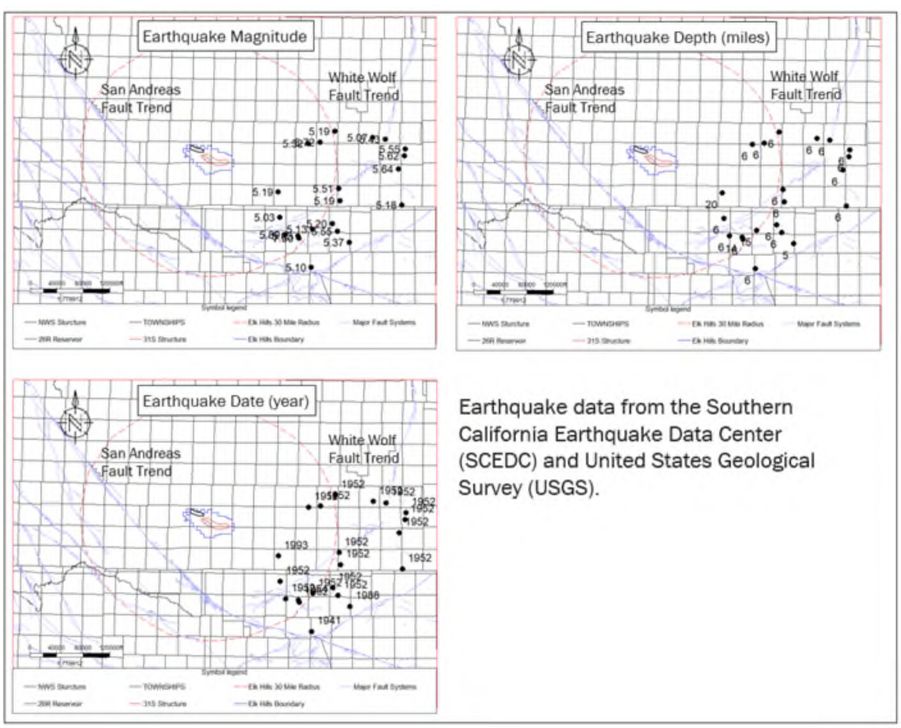
Seismic History:

The EHOF is in a seismically active region, but no active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area (DOE, 1997). Active seismicity near the project site is related to the San Andreas Fault (located 12 miles west) and the White Wolf Fault (25 miles southeast from the EHOF). Activity on these faults occurs far deeper than the Monterey formation (~8,500 feet.) at about 6 miles below surface.

Historical seismic events were gathered from the publicly available Southern California Earthquake Data Center (SCEDC) and the USGS databases. Seismicity is monitored. The SCEDA is the most complete data set and has compiled all available historic seismic data holdings in southern California to create a single source for online access to southern California earthquake data. The Catalog goes back to the beginning of routine seismological operations by the Caltech Seismological Laboratory in 1932 (SCEDC website).

Within the EHOF there have been no earthquakes recorded greater than 3.0. In addition, there have only been eight earthquakes with a magnitude of 5.0 or greater within a 30-mile radius around the EHOF (Figure 24). The average depth of these earthquakes is 6.3 miles. Through monitoring via surface and borehole seismometer installation, CTV will establish a baseline and assess natural versus induced seismicity.

**Figure 24: Earthquakes in the San Joaquin Basin with a magnitude greater than 5 since 1932. The White Wolf Fault is active in the southern San Joaquin Basin.**



Seismic Risk:

The EHOF has been closely monitored for the effects of seismicity by CRC and previous owners and operators of the field. The San Joaquin Valley is seismically active outside the EHOF, but no basin wide events have impacted the Elk Hills reservoirs and oil and gas infrastructure. This is due, in part, to the thickness and high level of clay in the primary confining layer Reef Ridge Shale.

1. No active faults have been identified by the State Geologist of the California Division of Mines and Geology (CDMG) for the Elk Hills area.
2. VS30, defined as the average seismic shear-wave velocity (VS) from the surface to a depth of 30 meters. Mapping completed by the USGS shows that the EHOF has very dense soil and soft rock based on the National Earthquake Hazards Reduction Program site classification. The high Vs30means (Figure 25) that the site has thin sediment and low factor amplification, reducing risk to surface facilities, wells, and other infrastructure.
3. The 1952 Kern County earthquake, the largest in the region, occurred southeast of the EHOF near Frazier Park with an estimated magnitude of 7.5. Effects of the earthquake were catastrophic with loss of life, and significant property damage (SCEDC). Regionally there were no reservoir containment issues associated with oil and gas operations and the Reef Ridge Shale. Moreover, there was no impact to Elk Hills infrastructure (Jenkins, 1955).

**Figure 25: VS30 analysis from the USGS that supports the EHOF has a low risk for shallow well and infrastructure impact due to earthquakes.**

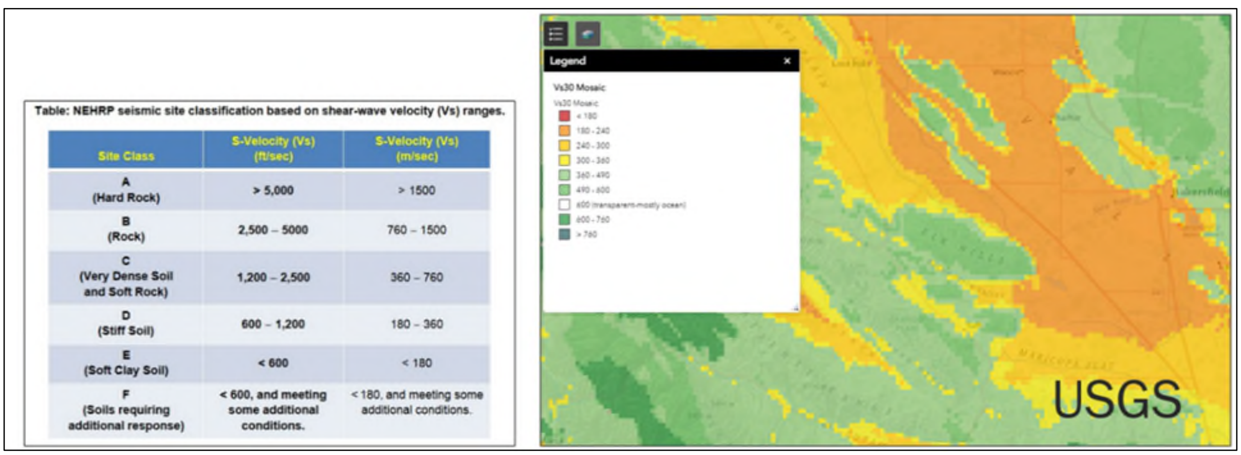


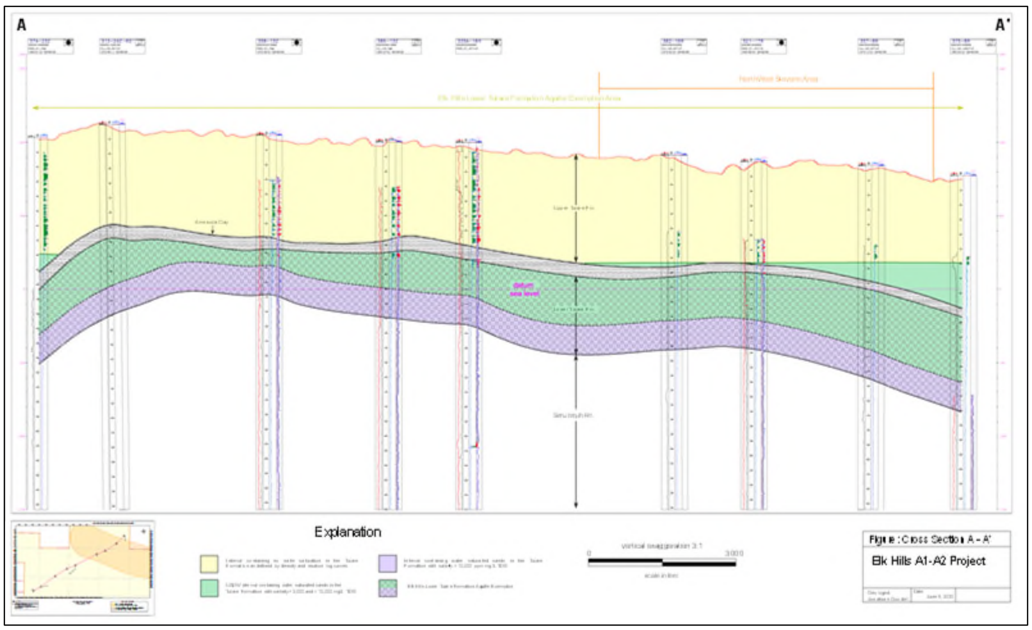
Table: NEHRP seismic site classification based on shear-wave velocity (Vs) ranges.

| Site Class | S-Velocity (Vs) (ft/sec) | S-Velocity (Vs) (m/sec) |
|---|---|---|
| A (Hard Rock) | > 5,000 | > 1500 |
| B (Rock) | 2,500 – 5000 | 760 – 1500 |
| C (Very Dense Soil and Soft Rock) | 1,200 – 2,500 | 360 – 760 |
| D (Stiff Soil) | 600 – 1,200 | 180 – 360 |
| E (Soft Clay Soil) | < 600 | < 180 |
| F (Soils requiring additional response) | < 600, and meeting some additional conditions. | < 180, and meeting some additional conditions. |

## *Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]*

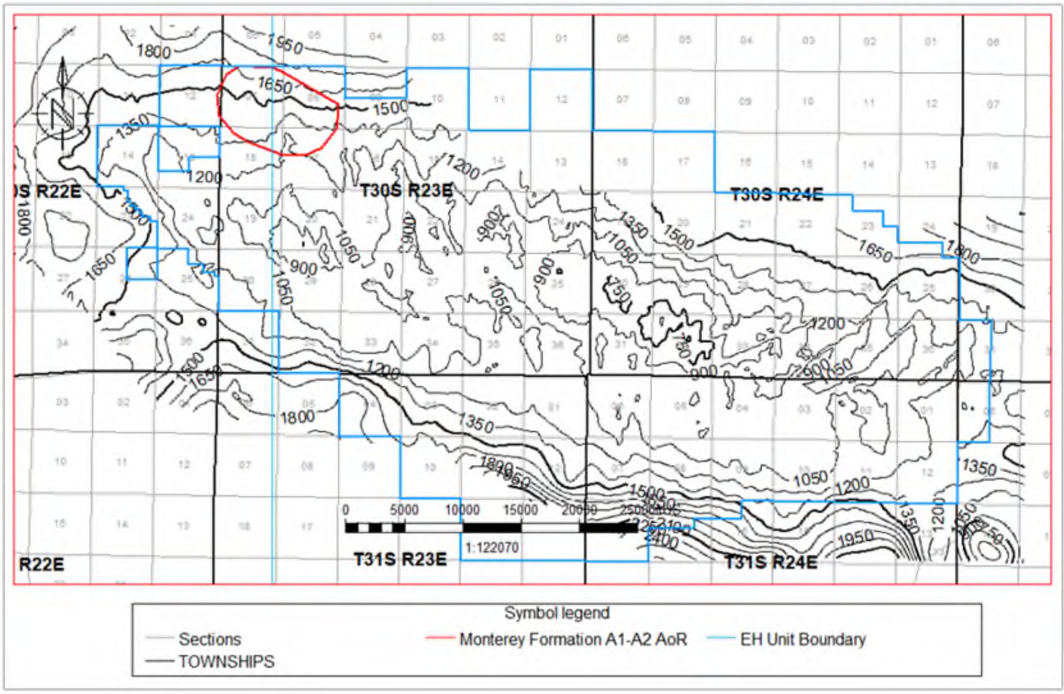
In the Elk Hills area, the Tulare Formation conformably overlies the shallow marine deposits of the San Joaquin Formation (Figure 26). CTV has studied the shallow aquifers at the EHOF extensively. Within the regional and site-specific area, the Tulare Formation is the only aquifer that contains water less than 10,000 mg/l TDS. There are no water wells nor springs within the AoR.

**Figure 26: Cross-section showing the Tulare Formation USDW. The Lower Tulare is an exempt aquifer (2018). The Upper Tulare air sands have 3,000 – 10,000 TDS water at the base, on the edges of the Northwest Stevens anticline.**



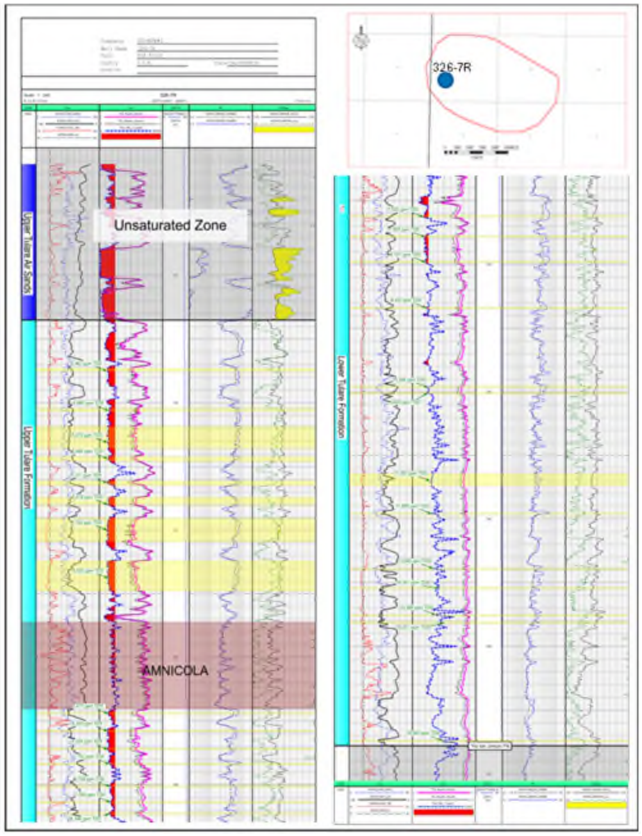

The Tulare Formation is Pliocene aged and is comprised of a thick succession of nonmarine sandstone, conglomerate, and shale beds. It is subdivided into the Upper and Lower Tulare separated by the sealing Amnicola Claystone (Figure 26). The depth is 600 - 2,500 feet and the thickness ranges from 1,200 - 1,500 feet (Figure 27).

**Figure 27: Tulare Formation isopach map.**




The upper intervals of the Tulare Formation consist of sand beds that that are completely dry or at irreducible water saturated and are referred to as the unsaturated zone. In the AoR the unsaturated zone is within the Upper Tulare USDW. The air sands-water contact in the Upper Tulare is determined from resistivity, density, and neutron geophysical logs (Figure 28). The characteristic density-neutron crossover (orange-filled intervals) is caused by the lack of fluid in the porous formation sands, and results in very low measured bulk density and very low measured neutron porosity. Figure 28 shows that the Upper Tulare USDW occupies the lowermost portion of the zone, overlain by the air sands.

**Figure 28: Type log for the Tulare Formation showing the Upper Tulare unsaturated zone, Upper Tulare USDW and Lower Tulare exempt aquifer.**




## Salinity Calculation

Calculation of salinity as shown in Figure 28 is a four step process:

(1) converting measured density to formation porosity

The equation to convert measured density to porosity is:

POR = (Rhom - RHOB) /( Rhom-Rhof )

Parameter definitions for the equation are:

POR is formation porosity
Rhom is formation matrix density grams per cubic centimeters (g/cc); 2.65 g/cc is used for sandstones
RHOB is calibrated bulk density taken from well log measurements (g/cc)
Rhof is fluid density (g/cc); 1.00 g/cc is used for water-filled porosity

(2) calculation of apparent water resistivity using the Humble equation,

The Humble equation calculates apparent water resistivity. The equation is:

Rwah = ((POR**m) * XRESD)/a

Parameter definitions for the equation are:

Rwah is apparent water resistivity (ohmm)
POR is formation porosity as derived from the density conversion formula
m is the cementation factor; 2.15 is the standard value
XRESD is deep reading resistivity taken from well log measurements (ohmm)

a is the archie constant; 0.62 is the standard value

(3) correcting apparent water resistivity to a standard temperature

Apparent water resistivity is corrected from formation temperature to a surface temperature standard of 75 degrees Fahrenheit:

Rwahc = Rwah * ((TEMP)+6.77)/(75+6.77)

Parameter definitions for the equation are:

Rwahc is apparent water resistivity (ohmm), corrected to surface temperature

TEMP is down hole temperature based on temperature gradient (DegF)

(4) converting temperature corrected apparent water resistivity to salinity.

The following formular was used:

SAL_h = 10 ** ((3.562-(Log10(Rwahc-0.0123)))/.955)

Parameter definitions for the equation are:

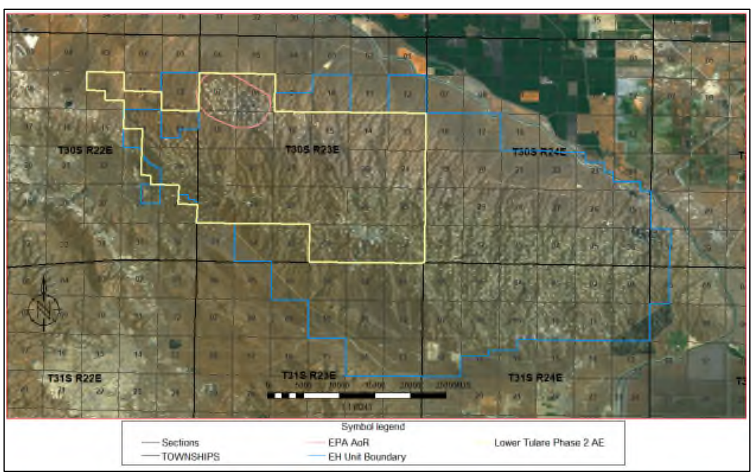
SAL_h is salinity from corrected Rwahc (ppm)

Rwahc is apparent water resistivity, corrected to surface temperature (ohmm),

Water Samples

Tulare Formation water within the AoR and the Elk Hill Oil Field is not utilized due to high TDS (3,000 – 10,000 mg/l) and concentrations of heavy metals above maximum containment levels (MCL).

**Figure 29: Lower Tulare aquifer exemption boundary.**




In 2018 the Lower Tulare aquifer (boundary shown on map in Figure 29) was exempted because the water meets the federal exemption criteria:

1. The portion of the formation for exemption in the field does not serve as a source of drinking water; and

2. The portion of the formation proposed for exemption in the field has more than 3,000 milligrams per liter (mg/L) and less than 10,000 mg/l TDS content and is not reasonably expected to supply a public water system.

The Upper Tulare USDW has 3,000-10,000 mg/l TDS on the edges of the NWS anticline. Water quality for the Upper Tulare USDW is shown in Figure 30. The water is not used within the AoR or the EHOF.

**Figure 30: Upper Tulare USDW and Lower Tulare Formation water analysis**.

Upper Tulare

Table 6a. WATER SOURCE WELL #43WS-133
WATER ANALYSIS DATA (mg/kg)

| DATE | 6-95 | 7-95 | 8-95 | 9-95 |
|---|---|---|---|---|
| SAMPLE # | 95094 | 95150 | 95182 | 95189 |
| CONSTITUENTS: | | | | |
| Calcium, Ca | 230 | 230 | 220 | 220 |
| Magnesium, Mg | 85 | 85 | 92 | 93 |
| Sodium, Na | 1280 | 1300 | 1200 | 1300 |
| Potassium, K | 5.2 | 5.8 | 5.8 | 6.6 |
| Iron, Fe | 0.4 | 0.51 | 0.38 | 0.54 |
| Hydroxide, OH | 0 | 0 | 0 | 0 |
| Carbonate, CO3 | 0 | 0 | 0 | 0 |
| Bicarb, HCO3 | 180 | 190 | 190 | 180 |
| Chloride, Cl | 1360 | 1400 | 1300 | 1400 |
| Sulfate, SO4 | 1600 | 1600 | 1500 | 1600 |
| Sulfide, S | <5.0 | <5.0 | <5.0 | <5.0 |
| Totals | 4660 | 4700 | 4400 | 4700 |
| Boron, B | 4.7 | 4.6 | 4.7 | 4.7 |
| TDS (Grav) | 4890 | 4800 | 4900 | 4900 |
| Hardness, CaCO3 | 920 | 920 | 930 | 930 |
| Alkalinity, CaCO3 | 150 | 160 | 160 | 150 |
| Sodium Chloride | 3690 | 3700 | 3500 | 3800 |
| | | | | |
| pH | 7.8 | 8.1 | 8.0 | 7.9 |
| Electrical Conductivity | 6.99 mmhos/cm | 7.02 mmhos/cm | 6.99 mmhos/cm | 6.99 mmhos/cm |
| Specific Gravity | 1.003 | 1.003 | 1.004 | 1.003 |
| Resistivity | 1.43 ohm | 1.43 ohm | 1.43 ohm | 1.43 ohm |
| NOTE: Sample analysis is from Zalco Laboratory. | | | | |

*(Source: NPR-1 Ground Water Monitoring Plan, 1995)*

Lower Tulare

**Water Analysis (General Chemistry)**

BCL Sample ID: 1411084-01 | Client Sample Name: Elk Hills Well 82-2B, 5/17/2014 4:05:00PM, Rick Ogletree

| Constituent | Result | Units | PQL | MDL | Method | MB Bias | Lab Quals |
|---|---|---|---|---|---|---|---|
| Electrical Conductivity @ 25 C (Field Test) | 27000 | umhos/cm | 1.0 | 1.0 | EPA-120.1 | | |
| pH (Field Test) | 7.23 | pH Units | 0.05 | 0.05 | EPA-150.1 | | |
| Temperature (Field Test) | 87.6 | F | 32.0 | 32.0 | SM-2550B | | |
| Total Calcium | 650 | mg/L | 2.0 | 0.30 | EPA-6010B | ND | A10 |
| Total Magnesium | 230 | mg/L | 1.0 | 0.38 | EPA-6010B | 0.75 | A10 |
| Total Sodium | 4700 | mg/L | 10 | 1.0 | EPA-6010B | ND | A01 |
| Total Potassium | 31 | mg/L | 20 | 2.6 | EPA-6010B | ND | A10 |
| Bicarbonate Alkalinity as CaCO3 | 59 | mg/L | 8.2 | 8.2 | EPA-310.1 | ND | |
| Carbonate Alkalinity as CaCO3 | ND | mg/L | 8.2 | 8.2 | EPA-310.1 | ND | |
| Hydroxide Alkalinity as CaCO3 | ND | mg/L | 8.2 | 8.2 | EPA-310.1 | ND | |
| Total Alkalinity as CaCO3 | 59 | mg/L | 8.2 | 8.2 | EPA-310.1 | ND | |
| Bromide | 50 | mg/L | 5.0 | 2.2 | EPA-300.0 | ND | A01 |
| Chloride | 10000 | mg/L | 50 | 6.7 | EPA-300.0 | 20 | A01 |
| Fluoride | ND | mg/L | 2.5 | 0.70 | EPA-300.0 | ND | A10 |
| Nitrate as NO3 | ND | mg/L | 22 | 5.5 | EPA-300.0 | ND | A10 |
| Sulfate | 320 | mg/L | 50 | 9.0 | EPA-300.0 | 19 | A01 |
| pH | 7.47 | pH Units | 0.05 | 0.05 | EPA-150.1 | | S05 |
| Electrical Conductivity @ 25 C | 26100 | umhos/cm | 1.00 | 1.00 | EPA-120.1 | | |
| Total Dissolved Solids @ 180 C | 20000 | mg/L | 1000 | 1000 | EPA-160.1 | ND | |

Ground Water Flow

The Elk Hills field is located within an area of the San Joaquin Basin which has only interior drainage and no appreciable surface or subsurface outflow. The Kern River, which is the primary source of surface water and fresh groundwater in the area, drains to the southeast and terminates near the northeastern side of the Elk Hills field. Precipitation in the Elk Hills area averages about 5.8 inches annually, with an average pan evaporation rate of about 108 inches per year in the Buttonwillow area. As a result, almost no groundwater from precipitation recharges the Tulare Formation groundwater, causing salts to become more concentrated over time and potentially resulting in high TDS concentrations.

Water Supply Wells

All available water supply well databases were reviewed for information on water wells in the site-specific area and proximity. This includes CalGEM, USGS, the Kern County Water Agency (KCWA), West Kern Water District, the California Department of Water Resources, and the GeoTracker Groundwater Ambient Monitoring and Assessment (GAMA) online database. CTV owns the surface area of the Elk Hills Unit in its entirety, and there are no records of water supply wells within the AoR.

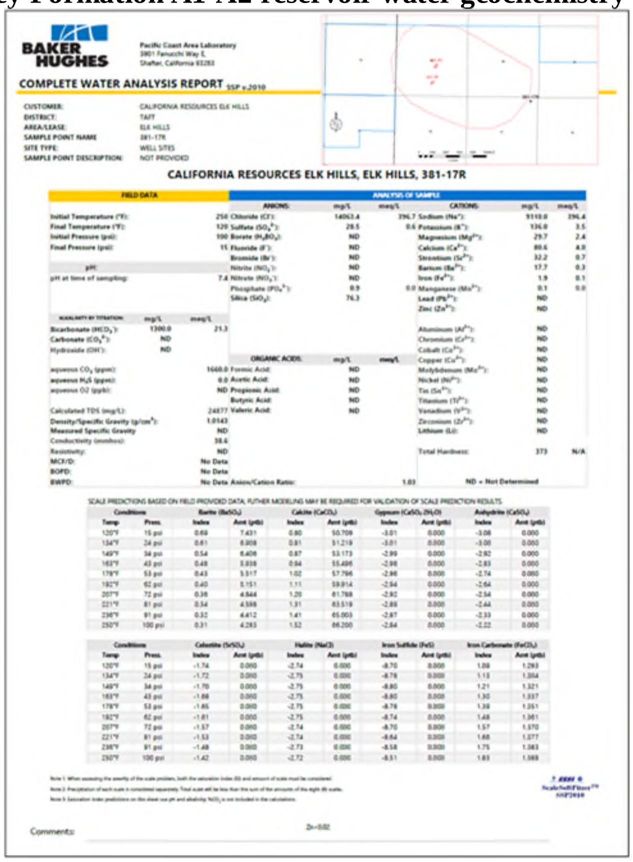
## *Geochemistry [40 CFR 146.82(a)(6)]*

Geochemistry A1-A2 Reservoir:

The Monterey Formation A1-A2 reservoir has a gas cap that overlies a thin oil band and a basal water zone. CRC and previous operators have collected baseline data used to characterize the reservoir. Produced fluid sampled during oil and gas operations is used to characterize the Monterey Formation A1-A2 geo-chemistry, this includes water and hydrocarbons (gas and oil). Geochemical results for the hydrocarbon and water analysis and total dissolved solids have been used as inputs for computational modeling.

Figure 31 shows the water chemistry from well 381-17R, taken from a sand underlying the Monterey Formation A1-A2 reservoir. Reservoir depletion of the Monterey Formation A1-A2 has reduced the water saturation to residual, preventing representative water sampling.

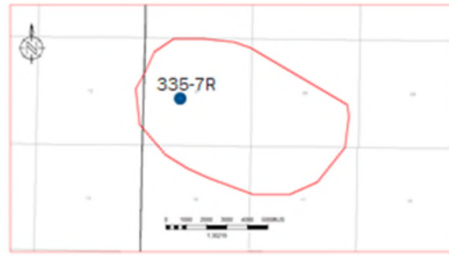
**Figure 31: Monterey Formation A1-A2 reservoir water geochemistry from well 381-17R.**




The hydrocarbon composition for the Monterey Formation A1-A2 reservoir was determined using chromatography in conjunction with low temperature, fractional distillation. Figure 32 shows the results of the hydrocarbon composition for well 335-7R within the AoR. Oil composition analysis was routinely completed upon reservoir discovery and was collected across the field. This original dataset is valid for the oil composition, as the hydrocarbon components are consistent to the present time.

**Figure 32: Monterey Formation A1-A2 hydrocarbon geochemistry from well 335-7R in 1974.**

| | | |
|---|---|---|
| Hydrogen Sulfide | Nil | Nil |
| Carbon Dioxide | 0.60 | 0.23 |
| Nitrogen | 0.04 | 0.01 |
| Methane | 45.77 | 6.43 |
| Ethane | 1.82 | 0.48 |
| Propane | 4.66 | 1.80 |
| iso-Butane | 1.32 | 0.67 |
| n-Butane | 3.74 | 1.90 |
| iso-Pentane | 1.39 | 0.88 |
| n-Pentane | 1.41 | 0.89 |
| Hexanes | 2.86 | 2.15 |
| Heptanes plus | 36.39 | 84.56 |
| | 100.00 | 100.00 |




Gas composition for the Monterey Formation A1-A2 is collected to assess the changing concentration of key components. Since 2011, CTV has used two injectors for reservoir pressure support; 357-7R and 355-7R to inject gas containing up to 44% $CO_2$. Figure 33 shows the produced natural gas analysis for 353-7R in 2021. Note that the composition has 6.5 mole % $CO_2$.

**Figure 33: Natural gas composition analysis for well 353-7R in 2021.**

CALIFORNIA RESOUCES CORPORATION
35R LABORATORY SERVICES

NATURAL GAS ANALYSIS

| | |
|---|---|
| LOG NUMBER : | NT210833 |
| SAMPLER NUMBER : | 353-7R |
| SAMPLE LOCATION : | 353-7R |
| SAMPLE SOURCE : | Well Head |
| SAMPLE TYPE : | A1-A2 |
| DATE SAMPLED : | 06/02/21 |
| TIME SAMPLED: | |
| PRESSURE (PSIG) : | |
| TEMPERATURE (F) : | |
| SAMPLED BY : | CD |
| REPORTED BY : | AR |
| REQUESTED BY : | NGL |


*Gas Chromatographic Analysis*

| COMPONENTS | NAME (Abreviated) | MOL % | GPMCF | BBL/MMSCF |
|---|---|---|---|---|
| OXYGEN | - O2 | 0.040 | | |
| NITROGEN | - N2 | 0.452 | | |
| CARBON DIOXIDE | - CO2 | 6.572 | | |
| METHANE | - C1 | 66.909 | | |
| ETHANE | - C2 | 5.078 | | |
| PROPANE | - C3 | 7.057 | 1.94 | 46.28 |
| ISO-BUTANE | - IC4 | 1.250 | 0.41 | 9.74 |
| N-BUTANE | - NC4 | 4.607 | 1.45 | 34.57 |
| ISO-PENTANE | - IC5 | 1.549 | 0.57 | 13.49 |
| N-PENTANE | - NC5 | 1.735 | 0.63 | 14.97 |
| HEXANES PLUS | - C6+ | 4.750 | 2.05 | 48.71 |
| | TOTAL: | 100.000 | 7.05 | 167.75 |

| | |
|---|---|
| C4+ (GPMCF) | 5.10 |
| Relative Density (Air = 1) : | 0.992 |
| Gross Heating Value (BTU/CU FT): | 1520 |
| Compressibility Factor, Z : | 0.9934 |

REMARKS:
1. Data are calculated at 60 F, 14.73 psia, dry, real gas.
2. Reference Methods: ASTM D-1945, ASTM D-3588, GPA-2145, GPA-2261, GPA-2172, GPA-2177.

Monterey Formation A1-A2 Reactions:

Mineralogy and formation fluid interactions have been assessed for the Monterey Formation. The following applies to potential reactions associated with the $CO_2$ injectate:

1. The Monterey Formation A1-A2 reservoir has a low current water volume (~15% saturation in the gas cap and 85% in the thin oil leg) due to production related to oil and gas operations, where four million net barrels of water have been produced. This low volume of water will minimize both the quantity of $CO_2$ that will dissolve in solution and the quantity of carbonic acid formed in-situ.
2. Residual oil saturation (15%) in the Monterey Formation A1-A2 reservoir will also dissolve only a small amount of $CO_2$.
3. The Monterey Formation A1-A2 has a negligible quantity of carbonate minerals and is instead dominated by quartz and feldspar. These minerals are stable in the presence of $CO_2$ and carbonic acid and any dissolution or changes that occur will be on grain surfaces.
4. Since 2011 6.3 billion cubic feet of gas has been injected in the 357-7R and 355-7R wells, consisting of up to 44% $CO_2$. Injectivity of the reservoir has not changed.

The oil and water $CO_2$ trapping mechanisms have been incorporated in the computational modeling and will be discussed in the AoR and Corrective Action Plan.

Reef Ridge Shale Confining Layer Reactions:

There is no geochemistry analysis for the Reef Ridge Shale. The shale will only provide fluid for analysis if stimulated. However, given the low permeability of the rock, high capillary entry pressure, and the low carbonate content, the Reef Ridge Shale is not expected to be impacted by the $CO_2$ injectate.

## *Site Suitability [40 CFR 146.83]*

The Monterey Formation A1-A2 reservoir in the Northwest Stevens anticline was discovered in the 1970's. For over 40 years the reservoir has been developed with the injection of water and gas to maintain reservoir pressure for improved oil recovery, Class II injection approved by CalGEM. This operating experience provides an intimate knowledge of the confining Reef Ridge Shale and the hydrodynamics of the Monterey Formation A1-A2 reservoir.

In support of the EPA Class VI application, CTV has fully characterized the site for suitability by integrating static data that includes well logs, three dimensional seismic and core data, as well as dynamic data that includes reservoir production, injection, and pressure data. The operational strategy of maintaining final reservoir pressure at or below the discovery pressure of the reservoir mitigates future confinement concerns.

A key component of the A1-A2 reservoir characterization was the development of a geo-cellular model, which is used to assess $CO_2$ plume development through simulation and computational modeling studies. Results from the studies support plume size, structural and stratigraphic confinement and storage capacity. A key input into the geo-cellular model is the characterization of reservoir facies (sand versus shale). Cross-sections in Figures 34 and 35 shows the lateral continuity of the sand facies within the reservoir. Sand continuity and lack of internal baffles and barriers supports predictable plume development.

CO2 Injectate Confinement:

Confinement of $CO_2$ injected into the storage reservoir is supported by the following:

1. Prior to discovery of the Monterey Formation A1-A2 reservoir, a gas cap with underlying oil was confined for several million years.
2. The Reef Ridge Shale primary confining layer is 1,500 feet thick over the storage reservoir and has <0.01 mD permeability. Confinement of the Reef Ridge Shale has been demonstrated by the injection of 175 billion cubic feet of gas and five million barrels of water with no leakage.
3. Cross section A-A' (Figure 34) shows the lateral confinement of the injected $CO_2$ plume by the anticline structure. CTV plans to maintain the reservoir pressure at or beneath the discovery pressure of the reservoir, ensuring that $CO_2$ does migrate beyond the edges of the anticline structure or into the Reef Ridge shale.
4. In Cross section B-B' (Figure 35) the up-dip $CO_2$ plume is confined by shale and the non-deposition of reservoir sands.

**Figure 34: Plume modeling results showing lateral confinement of the CO2 plume by the edges of the anticline structure.**

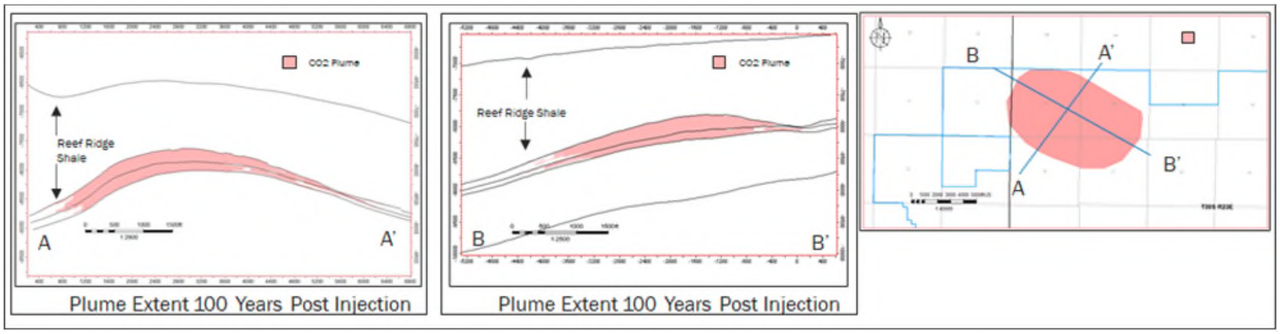
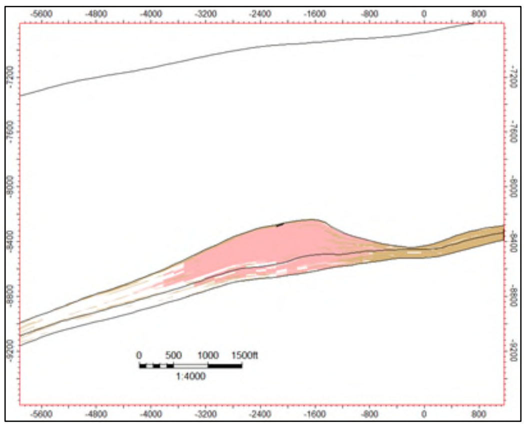



**Figure 35: Plume modeling results showing the confinement of the plume against the up- dip pinch-out of the A1-A2 sand facies and the increasing shale facies.**




Storage capacity for the Monterey Formation A1-A2 storage reservoir based on computational modeling results is approximately 8 -10 million tonnes of $CO_2$. This is sufficient capacity for the total proposed injectate.

## AoR and Corrective Action

CTV's AoR and Corrective Action plan pursuant to 40 CFR 146.82(a)(4), 40 CFR 146.82(a)(13) and 146.84(b), and 40 CFR 146.84(c) describes the process, software and results to establish the AoR, and the wells that require corrective action.

| **AoR and Corrective Action GSDT Submissions** |
| --- |
| ***GSDT Module:*** AoR and Corrective Action<br>***Tab(s):*** All applicable tabs<br><br>Please use the checkbox(es) to verify the following information was submitted to the GSDT:<br>☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]***<br>☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]***<br>☒ Computational modeling details ***[40 CFR 146.84(c)]*** |

## Financial Responsibility

CTV's Financial Responsibility demonstration pursuant to 140 CFR 146.82(a)(14) and 40 CFR 146.85 is met with a line of credit for Injection Well Plugging and Post-Injection Site Care and Site Closure and insurance to cover Emergency and Remedial Responses.

| **Financial Responsibility GSDT Submissions** |
| --- |
| ***GSDT Module:*** Financial Responsibility Demonstration<br>***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs<br><br>Please use the checkbox(es) to verify the following information was submitted to the GSDT:<br>☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]*** |

## Injection Well Construction

CTV plans to utilize existing injectors, 357-7R and 355-7R, for the Elk Hills A1-A2 Storage project. These injectors are currently approved by CalGEM for Class II injection of gas (up to 44% $CO_2$) for the purpose of reservoir pressure maintenance. The approval is for four injectors at a maximum injection rate of 50 million cubic feet per day. These wells have been engineered for the injection of $CO_2$ with appropriate materials able to minimize corrosion and to ensure that the wellbore stresses are within specifications and standards given the planned operating conditions. Previous and current injectors used to maintain reservoir pressure injected 175 billion cubic feet of natural gas with injection rates as high as 30 million cubic feet per day for individual wells.

## *Construction Procedures [40 CFR 146.82(a)(12)]*

Injectate Migration Prevention:

357-7R was drilled in 1980, during which time there were no drilling and completion issues. The well was constructed to prevent migration of fluids out of the Monterey Formation, protect the USDW and allow for monitoring:

1. Conductor, surface, and intermediate casing.
2. Cement across each casing string with cement returns to surface during completion. A cement bond log was acquired to confirm cement along the well.
3. Casing specifications exceed the operating conditions of the well (Table 5).
4. Long string casing diameter of seven inches with stainless steel tubing of 4.5 inches. This casing and tubing size will enable monitoring devices to be installed, cased hole logs to be acquired and Mechanical Integrity Testing (MIT) to be conducted.

Attachment G: Construction Details provides more detail related to the construction of well 357-7R.

Materials:

All well materials are designed to be compatible with the $CO_2$ injectate and will limit corrosion:

1. Tubing –13 CR-95
2. Wellhead – stainless steel
3. Packer – nickel plating and hardened rubber
4. Casing and Cement - N-80 casing with Portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with $CO_2$ with good cement bond between formation and casing. A cement bond log was acquired to ensure bond between casing and formation.

Standards:

Well materials follow the following standards:

1. Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
2. Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
3. Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

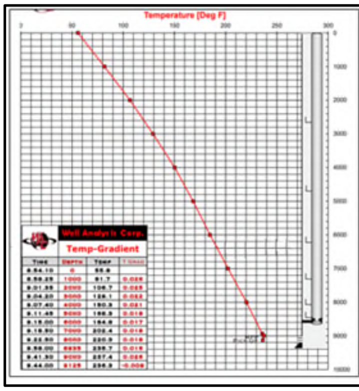
**Casing and Cementing**

Casing:

Monterey Formation A1-A2 temperature is approximately 240 degrees Fahrenheit. These conditions are not extreme, and normal cementing and casing practices meet standards. Temperature differences between the $CO_2$ injectate and reservoir will not affect well integrity.

Casing specifications are presented in Table 5. These specifications show that the well was engineered to standards that allow for the safe operation at an injection pressure that will not be greater than 4,500 PSI. Wells with similar construction methods have been used in Elk Hills for gas injection with no operational issues related to the structural strength.

**Table 5: Temperature profile and casing construction data for the 357-7R injector.**




| Name | Depth Interval (feet) | Outside Diameter (inches) | Inside Diameter (inches) | Weight (lb/ft) | Grade (API) | Design Coupling (Short or Long Threaded) | Thermal Conductivity @ 77°F (BTU/ft hr, °F) | Burst Strength (psi) | Collapse Strength (psi) |
|---|---|---|---|---|---|---|---|---|---|
| Conductor | 20-60 | 20.000 | 19.5 | 52 | H-40 | Short | 31 | 875 | 90 |
| Surface | 20-501 | 13.375 | 12.715 | 48 | H-40 | Short | 31 | 1,727 | 740 |
| Intermediate | 20-3,517 | 9.625 | 8.835 | 40 | N-80 | Long | 31 | 5,750 | 3,090 |
| Long-string | 20-8,990 | 7.000 | 6.184<br>6.276<br>6.366 | 29<br>26<br>23 | N-80 | Long | 31 | 8,160<br>7,240<br>6,340 | 7,020<br>5,410<br>3,830 |

Cement:

Class G Portland cement has been used to complete the well. This cement is widely used in $CO_2$-EOR wells and has been demonstrated to have properties that are not deleterious with $CO_2$. The cement returns were to surface for each stage. Cementing was completed in stages to ensure cement between casing and the formation.

Protection of USDW:

The USDW and all strata overlying the injection zone will be protected by the following:

1. A cement bond log was run on the well post completion to ensure adequate bond to casing and formation.
2. Standard annular pressure test (SAPT) have been acquired through time that increases the well annulus pressure to 500 PSI for 30 minutes. All SAPT's demonstrate that the production casing (and packer) has mechanical integrity, with no casing or packer leaks. SAPT will be acquired before the start of injection and every five years thereafter.
3. If there are mechanical integrity issues in the future, CTV will run a casing inspection log to assess casing thickness.

**Table 6. Casing details.**

| Casing String | Casing Depth | Borehole Diameter | Wall Thickness | External Diameter | Casing Material | String Weight |
|---|---|---|---|---|---|---|
| Conductor | 60 | 24 | 0.55 | 20 | J-55 | 94 |
| Surface | 501 | 17.5 | 0.33 | 13.375 | H-80 | 48 |
| Intermediate | 3516 | 12.25 | 0.395 | 9.625 | N-80 | 40 |
| Long String | 2,953 | 8.75 | 0.317 | 7 | N-80 | 23 |
| | 6,158 | 8.75 | 0.362 | 7 | N-80 | 26 |
| | 6,158 – 8,990 | 8.75 | 0.408 | 7 | N-80 | 29 |

*Tubing and Packer*

The information in this table meets the minimum requirements at 40 CFR 146.86(c).

**Table 7. Tubing and packer details.**

| Material | Setting Depth | Tensile Strength | Burst Strength | Collapse Strength | Material |
|---|---|---|---|---|---|
| Tubing | 8,454 | 105,000 | 12,450 | 12,760 | 13 CR-95 |
| Packer | 8,447 | 10,000 | 8,160 | 7,020 | Baker-Hornet, Ni plated |

## Pre-Operational Logging and Testing

CTV has provided operational and testing data to support the Elk Hills A1-A2 project. Data and information provided meets the requirements pursuant to 40 CFR 146.82(a)(8) and 40 CFR 146.87.

| **Pre-Operational Logging and Testing GSDT Submissions** |
|---|
| ***GSDT Module:*** Pre-Operational Testing<br>***Tab(s):*** Welcome tab<br><br>Please use the checkbox(es) to verify the following information was submitted to the GSDT:<br>☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]*** |

## **Well Operation**

### ***Operational Procedures [40 CFR 146.82(a)(10)]***

Injectors will be operated to inject the desired rate of super-critical (SC) phase $CO_2$. For attaining SC flow, surface injection pressure will be a minimum of 1,200 PSI. As the depleted oil reservoir fills up, a higher surface injection pressure will likely be required. Final reservoir pressure target is 4,000 PSI. It is assumed that at time of shut-in, the downhole injection pressure will be ~4,500 PSI.

Table 8 values shown below for average injection pressure are an average of initial conditions and final conditions. As the reservoir fills up with $CO_2$ it will pressure up, thus creating a continually changing reservoir and injector condition over injection life. A downhole injection pressure of ~4,500 PSI is assumed to occur at shut-in timing when reservoir pressure has reached its final level at 4,000 PSI. This translates to a surface injection pressure of ~2,000 PSI, which will be achieved via a surface booster pump.

The final/maximum values for surface and downhole injection pressures are far below (~2,000 psi) those associated with the Class II permitted fracture gradients of .8 psi/foot. 40+ years of gas and water injection experience into A1-A2 Stevens supports that these operating limits are appropriate and effective. Additionally, the final reservoir pressure target of 4,000 PSI is significantly below the Reef Ridge confining shale estimated minimum geomechanical failure pressure of ~7,500 PSI.

As mentioned above, as the reservoir fills up with $CO_2$, the reservoir pore pressure will increase. A surface booster pump will be needed to supplement surface injection pressure from the initial value of ~1,200 PSI to the final requirement of ~2,000 PSI.

### ***Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]***

There are currently multiple sources of anthropogenic $CO_2$ being considered for Stevens A1-A2 sequestration. These include capture off of the Elk Hills NGCC Power Plant as well as 3rd party existing and proposed industrial sources in the Southern San Joaquin Valley area. The carbon dioxide stream will consist of a minimum of 95% $CO_2$ by volume. Other key constituents that will be controlled for corrosion mitigation include water content (25#/mmscf) and oxygen level (<50 ppm)

Corrosiveness of the $CO_2$ stream is very low as long as the entrained water is kept in solution with the $CO_2$. This is ensured by the 25#/mmscf injectate specification referred to above. Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. In early injection time, it is likely that gas phase $CO_2$ will exist towards the lower depths of the tubing string. Stainless steel (13 CR-95) tubing will be used in the injection wells to mitigate this potential corrosion impact should free-phase water be present.

**Table 8. Proposed operational procedures.**

| Parameters/Conditions | Limit or Permitted Value | Unit |
|---|---|---|
| Maximum Injection Pressure | UIC Class II frac gradient .8 psi/ft | |
| Surface | 3,800 | psig |
| Downhole | 6,100 | psig |
| Average Injection Pressure | Average over time | |
| Surface | 1,600 | psig |
| Downhole | 4,100 | psig |
| Maximum Injection Rate | 30 per well | mmscfpd |
| Average Injection Rate | 10-15 per well | mmscfpd |
| Maximum Injection Volume and/or Mass | 10 million | tonnes |
| Average Injection Volume and/or Mass | 8 million | tonnes |
| Annulus Pressure | 3,730 @ packer | psig |
| Annulus Pressure/Tubing Differential | 370@ packer @ average injection condition | psig |

## Testing and Monitoring

CTV's Testing and Monitoring plan pursuant to 40 CFR 146.82 (a) (15) and 40 CFR 146.90 describes the strategies for testing and monitoring to ensure protection of the USDW, injection well mechanical integrity, and plume monitoring.

**Testing and Monitoring GSDT Submissions**

***GSDT Module:*** Project Plan Submissions
***Tab(s):*** Testing and Monitoring tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

## Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

**Injection Well Plugging GSDT Submissions**

***GSDT Module:*** Project Plan Submissions
***Tab(s):*** Injection Well Plugging tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

## Post-Injection Site Care (PISC) and Site Closure

CTV has developed a Post-Injection Site Care and Site Closure plan pursuant to 40 CFR 146.93 (a) to define post-injection testing and monitoring.

At this time CTV is not proposing an alternative PISC timeframe.

| **PISC and Site Closure GSDT Submissions** |
|---|
| ***GSDT Module:*** Project Plan Submissions<br>***Tab(s):*** PISC and Site Closure tab<br><br>Please use the checkbox(es) to verify the following information was submitted to the GSDT:<br>☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]*** |
| ***GSDT Module:*** Alternative PISC Timeframe Demonstration<br>***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested)<br><br>Please use the checkbox(es) to verify the following information was submitted to the GSDT:<br>☐ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]*** |

## Emergency and Remedial Response

CTV's Emergency and Remedial Response plan pursuant to 40 CFR 164.94 describes the process and response to emergencies to ensure USDW protection.

| **Emergency and Remedial Response GSDT Submissions** |
|---|
| ***GSDT Module:*** Project Plan Submissions<br>***Tab(s):*** Emergency and Remedial Response tab<br><br>Please use the checkbox(es) to verify the following information was submitted to the GSDT:<br>☒ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]*** |

# References:


1. Callaway, D.C., and Rennie, E.W., Jr., 1991, San Joaquin Basin, California, in Gluskoter, H.J., Rice, D.D., and Taylor, R. B., eds., Economic geology, U.S.: Boulder, Colorado, Geological Society of America, The Geology of North America, v. P-2, p. 417-430.
2. Zumberge, John, Russell, Just and Reid, Stephen, Charging of Elk Hills reservoirs as determined by oil geochemistry, AAPG Bulletin, v. 89, no. 10 (October 2005), pp. 1347–1371.
3. Hosford, Allegra and Magoon, Les, 2007 Age, U.S. Geological Survey Professional Paper 1713, California Petroleum Systems and Geologic Assessment of Oil and Gas in the San Joaquin Basin Province, California, Chapter 5.
4. Maher, J. C., R. D. Carter, and R. J. Lantz, 1975, Petroleum geology of naval petroleum reserve No. 1, Elk Hills, Kern County, California: U.S. Geological Survey Professional Paper 912, 109 p.
5. Castilla, Davis and Younker, Leland, 1997, David A. Castillo Leland W. Younker A High Shear Stress Segment along the San Andreas Fault: Inferences Based on Near-Field Stress Direction and Stress Magnitude Observations in the Carrizo Plain Area, Lawrence Livermore National Laboratory.
6. Ingram G. M., Urai J. L., Naylor M. A. (1997) in Hydrocarbon Seals: Importance for Exploration and Production, Sealing processes and top seal assessment, Norwegian Petroleum Society (NPF) Special Publication, eds Moller-Pedersen P., Koestler A. G. **7**, pp 165–175.

**ATTACHMENT G: CONSTRUCTION DETAILS**
**WELL 357-7R**

**Elk Hills A1-A2 Storage Project**

## Facility Information

| | |
|---|---|
| Facility name: | Elk Hills A1-A2 Storage<br>357-7R |
| Facility contact: | Kenneth Haney / CCS Project Manager<br>28590 Highway 119<br><br>Tupman, CA 93276<br>(661) 763-6101/ Kenneth.Haney@crc.com |
| Well location: | Elk Hills Oil Field, Kern County, CA<br>35.32802963 / -119.5449982 |

## Introduction

The testing activities at the 357-7R described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C, along with other non-well related pre-injection baseline activities such as geochemical monitoring.

Injection well 357-7R is an existing well approved for gas injection as part of a UIC approval for pressure maintenance. The well has cumulative injection of 3.5 billion cubic feet of gas. As part of the UIC approval, California Resources Corporation (CRC) has conducted annual MITs and SAPT tests every five years to ensure internal and external mechanical integrity.

## Injection Well Construction Details

### *Casing Specifications*

| Name | Depth Interval (feet) | Outside Diameter (inches) | Inside Diameter (inches) | Weight (lb/ft) | Grade (API) | Design Coupling (Short or Long Threaded) | Thermal Conductivity @ 77°F (BTU/ft hr, °F) | Burst Strength (psi) | Collapse Strength (psi) |
|---|---|---|---|---|---|---|---|---|---|
| Conductor | 20-60 | 20.000 | 19.5 | 52 | H-40 | Short | 31 | 875 | 90 |
| Surface | 20-501 | 13.375 | 12.715 | 48 | H-40 | Short | 31 | 1,727 | 740 |
| Intermediate | 20-3,517 | 9.625 | 8.835 | 40 | N-80 | Long | 31 | 5,750 | 3,090 |
| Long-string | 20-8,990 | 7.000 | 6.184<br>6.276<br>6.366 | 29<br>26<br>23 | N-80 | Long | 31 | 8,160<br>7,240<br>6,340 | 7,020<br>5,410<br>3,830 |

### *Tubing Specifications*

| Name | Depth Interval (feet) | Outside Diameter (inches) | Inside Diameter (inches) | Weight (lb/ft) | Grade (API) | Design Coupling (Short or Long Thread) | Burst strength (psi) | Collapse strength (psi) |
|---|---|---|---|---|---|---|---|---|
| Injection tubing | 8,454 | 4.500 | 3.826 | 15.2 | 13CR-95 | Long (premium) | 12,450 | 12,760 |

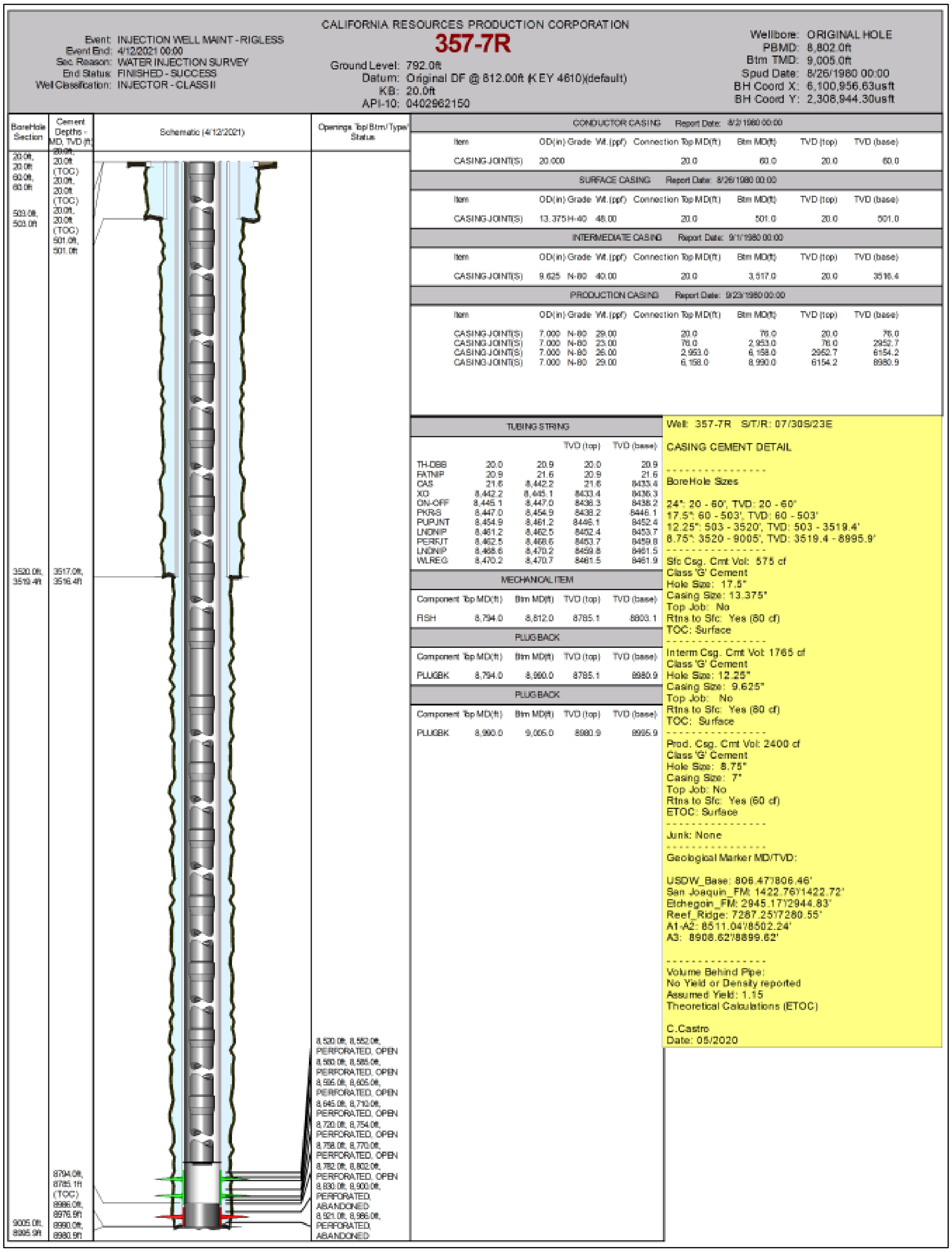
***Packer Specifications***

| Packer Type and Material | Packer Setting Depth (feet bgs) | Length (inches) | Nominal Casing Weight (lbs/ft) | Packer Main Body Outer Diameter (inches) | Packer Inner Diameter (inches) |
|---|---|---|---|---|---|
| Baker-Hornet, Ni plated | 8,447 | 95.4 | 23-29 | 6.000 | 2.920 |

| Tensile Rating (lbs) | Burst Rating (psi) | Collapse Rating (psi) | Max. Casing Inner Diameter (inches) | Min. Casing Inner Diameter (inches) |
|---|---|---|---|---|
| 10,0000 | 8,000 | 8,000 | 6.466 | 6.184 |

*Injection Well Construction Diagrams*

**Figure 1: Injection well 357-7R casing diagram.**




## Pre-Injection Testing Plan – Injection Well

The following tests and logs have been acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The tests and procedures are described below and in the Proposed Injection Well Construction Information section of the permit application.

***Deviation Checks***

Deviation measurements were conducted approximately every 10 feet during construction of the well.

***Tests and Logs***

*The following logs were acquired during the drilling and prior to the completion of the 357-7R well:*

- Array Compensated True Resistivity Log
- Spontaneous Potential Logs
- Caliper Logs
- Compensated Spectral Natural Gamma Log
- Spectral Density Dual Spaced Neutron Log
- Mud Log

*The following cased-hole logs were acquired after the drilling and completion of the 357-7R well:*

- Cement Bond Log
- Mechanical Integrity Tests (Temperature Log and SAPT)

***Demonstration of mechanical integrity***

Below is a summary of the tests to be performed prior to injection:

| Class VI Rule Citation | Rule Description | Test Description | Program Period |
|---|---|---|---|
| **40 CFR 146.89(a)(1)** | MIT - Internal | SAPT | Prior to operation |
| **40 CFR 146.87(a)(4)** | MIT - External | Temperature Log | Prior to operation |
| **40 CFR 146.87(a)(4)** | MIT - External | Radioactive Tracer | Prior to operation |

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

## Pre-Injection Testing Plan – Deep Monitoring Wells 327-7R-RD1 and 342-7R-RD1

Deep monitoring wells proposed for the Elk Hills A1-A2 Storage project have already been drilled and completed.

***Deviation Checks***

Deviation measurements for 342-7R-RD1 and 327-7R-RD1 were recorded approximately every 35 and 156 feet respectively, during construction of the well.

***Tests and Logs***

*The following logs were acquired during the drilling and prior to the completion of the 342-7R-RD1 and 327-7R-RD1 wells:*

- Array Compensated True Resistivity Log
- Spontaneous Potential Logs
- Caliper Logs
- Compensated Spectral Natural Gamma Log
- Spectral Density Dual Spaced Neutron Log

***Demonstration of mechanical integrity***

CTV will run mechanical integrity logs and tests prior to injection operations.

**Annulus Pressure Test Procedures for Injection Well 357-7R:**

1. The tubing/casing annulus (annulus) will be completely filled with liquid. The volume of fluid required will be measured;

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test;

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve; and

4. The annulus system must remain isolated for a period of no less than 60 minutes During the period of isolation measurements of pressure will be made at ten-minute intervals;

**Annulus Pressure Test Procedures for Monitoring Well 327-7R-RD1 & 342-7R-RD1:**

1. The tubing/casing annulus (annulus) will be completely filled with liquid. The volume of fluid required will be measured;

2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test;

3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system must be isolated from the source(annulus tank) by a closed valve; and

4. The annulus system must remain isolated for a period of no less than 60 minutes During the period of isolation measurements of pressure will be made at ten-minute intervals;

**<u>Pressure Fall-Off Test Procedures:</u>**

The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV does not currently plan to complete pressure fall off testing. The Monterey Formation A1-A2 reservoir is a depleted oil and gas reservoir with known reservoir continuity, boundaries, and flow properties from decades of water and gas injection. CTV may address scaling through time by acidizing the well to clean out the perforations.

CTV will consider pressure fall-off testing if injection rate decreases, with a simultaneous injection pressure increase outside the results from computational modeling.

***Testing details***

Pressure fall-off testing procedures are described below:

1. Injection rate will be held constant prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.

2. Upon shutting-in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.

3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

Pressure sensors used for this test will be the wellhead gauges and a downhole gauge for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

## Class VI UIC Project Information Tracking

This submission is for:

Project ID: R09-CA-0003

Project Name: CRC CalCapture A1-A2

Current Project Phase: Pre-Injection Prior to Construction

## General Information

Number of proposed Class VI wells: 2

Brief description of the project: The CTV Elk Hills A1-A2 project will inject CO2 for geologic sequestration at the Elk HIlls Oil Field. The CO2 injectate will be anthropogenically sourced.

Underground Injection Control (UIC) Program under Safe Drinking Water Act (SDWA)

Description: Class VI injection into the Elk Hills A1-A2 reservoir.

## Facility and Owner/ Operator Information

Facility name: Elk Hills A1-A2

Facility mailing address: 4809 Elk Hills Rd Tupman, CA 93276

Facility location: Latitude: 35.278 Longitude: -119.469

Up to four Standard Industrial Classification (SIC) codes for the products/services provided by the facility: 4911, 13

Facility located on Indian lands: No

Facility contact information

Contact person: Travis Hurst

Contact's business phone number: 661 - 342 - 2409

Contact's business email: travis.hurst@crc.com

Operator's name: Carbon TerraVault 1 LLC

Operator's business address: 28590 Highway 119 Tupman, CA 93276 (661) 342-2409

Operator's business phone number: 661 - 342 - 2409

Operator's status: Private

Ownership status: Owner

## Initial Permit Application

Permit Application Narrative: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/ProjInfo-08-02-2021-1953/Attachment--A-----Narrative-----Low--Resolution.pdf

Proposed project plans, submitted with the Project Plan Submission module:

An Area of Review (AoR) and Corrective Action Plan

A Testing and Monitoring Plan

A Well Plugging Plan

A Post-Injection Site Care (PISC) and Site Closure Plan

An Emergency and Remedial Response Plan

Computational modeling information, submitted with the Area of Review Computational Modeling module

A financial responsibility demonstration, submitted with the Financial Responsibility Demonstration module

A proposed pre-operational logging and testing program, submitted with the Pre-Operational Testing module

Other Required Information: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/ProjInfo-08-02-2021-1953/Draft--Att--G-----Construction--Details--Final.pdf

## Updated Information

A final AoR delineation and a final corrective action status, submitted with the Area of Review Computational Modeling module; if no updates are needed, please include a justification in the narrative file

The results of all required formation testing and well logging and testing, using the Pre-Operational Testing module (required for all projects)

AoR and Corrective Action Plan

Testing and Monitoring Plan

Well Plugging Plan

PISC and Site Closure Plan

## Complete Submission

Authorized submission made by: Travis Hurst

Comments regarding this submission: Several data files and submissions limitied by GSDT size limitations. For PDF doccuments with greater reolution, please contact.

For confirmation a read-only copy of your submission will be emailed to: travis.hurst@crc.com

# Class VI Injection Well: Quality Assurance and Surveillance Plan

July 15, 2021

Prepared by:

**Carbon TerraVault 1 LLC**

# Table of Contents

## List of Tables



## List of Figures

## Title and Approval Sheet

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at the Elk Hills A1-A2 Storage facility. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

THurst — July 15, 2021

Signature — Date

Travis Hurst

Geological Advisor

## Distribution List

The following project participants will receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project.

Ken Haney: Project Manager
Travis Hurst: Geological Advisor

Carbon TerraVault
28590 Highway 119
Tupman, CA 93276

# A. Project Management

## A.1. Project/Task Organization

A.1.a/b. Key Individuals and Responsibilities

The Elk Hill A1-A1 Storage project, led by Carbon TerraVault 1 LLC (CTV), includes participation from service providers. The responsibilities for Testing and Monitoring will be shared between CTV and the service providers.

CTV will be responsible for any data and submissions made to the EPA.

A.1.c. Independence from Project QA Manager and Data Gathering

CTV utilizes a third-party service provider to collect, transport and analyze samples as part of the Testing and Monitoring Plan.

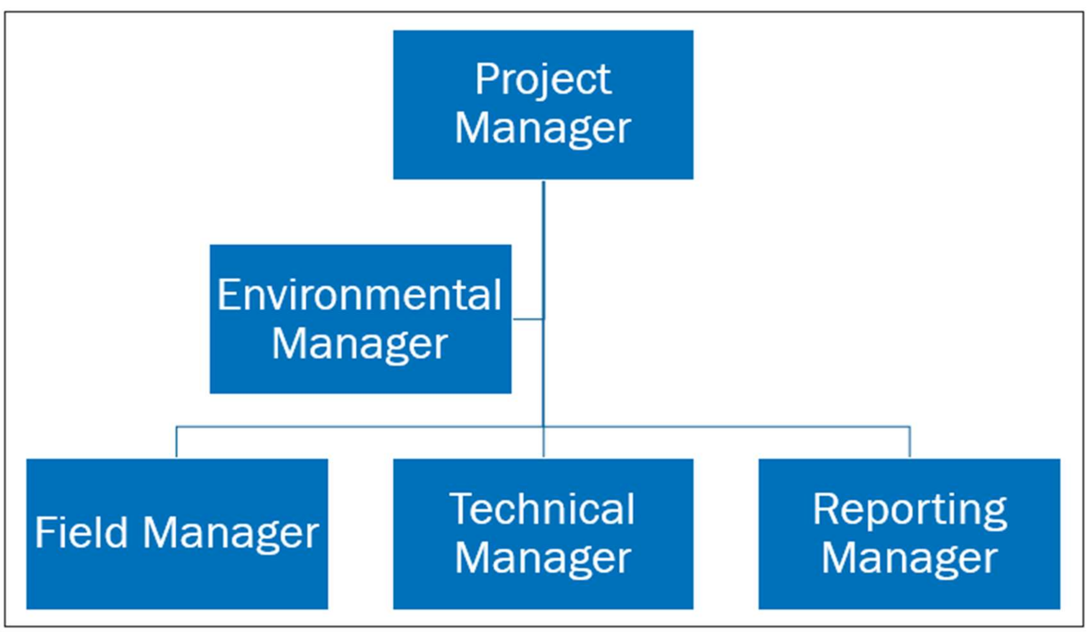
A.1.d. QA Project Plan Responsibility

CTV will be responsible for the Quality Assurance and Surveillance Plan. CTV will review the plan with service providers periodically.

A.1.e. Organizational Chart for Key Project Personnel

Figure 1 shows the organizational structure for the Elk Hills A1-A2 project. Although these roles have not been filled because the project is not operational, the chart shows the breakdown in responsibilities for future positions.

**Figure 1: Organizational Chart.**



## A.2. Problem Definition/Background

A.2.a. Reasoning

The Elk Hills A1-A2 project will inject and sequester $CO_2$ from sources that include the Elk Hills Power Plant, renewable diesel refinery projects, and other industrial sources close to the field. The project requires a comprehensive monitoring plan that gathers data to assess confinement of the $CO_2$ injectate. To ensure accurate measurement and reporting this QASP outlines detail associated with the surveillance related to sampling, operating, and recording.

A.2.b. Reasons for Initiating the Project

CTV initiated the project for ESG purposes and to reduce carbon footprint for CTV operations and for external emissions. The Elk Hills Oil Field is a premier location for carbon sequestration in the San Joaquin Basin. The field has available pore space, proven confinement, and ideal surface/mineral ownership.

A.2.c. Regulatory Information, Applicable Criteria, Action Limits

$CO_2$ injection as per standard operating procedures and regulations requires that the injectate is confined in the reservoir and that groundwater is not impacted. As such the following monitoring is necessary:

1. Injection well mechanical integrity testing
2. Injection well testing and operating data collection
3. Groundwater monitoring
4. Validation of the $CO_2$ plume areal coverage as defined by numerical modeling

The information and data below define the steps to ensure that monitoring data quality provides the confidence and information to verify confinement.

## A.3. Project/Task Description

A.3.a/b. Summary of Work to be Performed

**Table 1. Summary of Testing and Monitoring.**

| Activity | Location(s) | Method | Analytical Technique | Lab/Custody | Purpose |
|---|---|---|---|---|---|
| Injection well | | | | | |
| Carbon dioxide stream analysis | Compressor | Direct Sampling | Chemical Analysis | Zalco Labs | Monitor Injectate |
| Injection rate and volume | Injection Well | Flow meter | Direct Measurement | NA | Monitor rate and volume |
| Injection pressure | Injection wellhead | Pressure gauge | Direct Measurement | NA | Monitor injection pressure |
| Annular pressure | Injection Wellhead | Pressure gauge | Direct Measurement | NA | Monitor annular pressure |
| Downhole pressure/ temperature | Injection Well | Downhole gauge | Direct Measurement | NA | Monitor reservoir pressure and temperature |
| Corrosion monitoring | Between compressor and wellhead | Corrosion Coupon | NA | Zalco Labs | Monitor corrosion of materials |
| Mechanical integrity | Injection Well | Internal: SAPT<br>External: Temperature Log | | NA | Wellbore Integrity |
| Cement Evaluation | Injection Well | Logging | Cement bond log | NA | Wellbore Integrity |

**Table 2. Monitoring Well Summary**

| Activity | Location(s) | Method | Analytical Technique | Lab/Custody | Purpose |
|---|---|---|---|---|---|
| Monitoring Wells Above Confining Layer | | | | | |
| Fluid Sampling<br>Tulare Formation (USDW) | 61WS-8R | Direct Sampling | Chemical Analysis | Zalco Labs | Monitor water quality |
| Pressure<br>Tulare Formation (USDW) | 61WS-8R | Pressure gauge | Direct Measurement | Zalco Labs | Monitor pressure |
| Pressure<br>Etchegoin Formation | 346-7R-RD1 | Pressure gauge | Direct Measurement | Zalco Labs | Monitor pressure |
| Monterey Formation A1-A2 Reservoir | | | | | |
| Pressure/Temperature | Monitoring Wells | Downhole gauge | Direct Measurement | NA | Monitor reservoir pressure and temperature |
| Pulse Neutron Log | Monitoring Wells | Wireline | Indirect | NA | $CO_2$ Saturation |

A.3.c. Geographic Locations

A.3.d. Resource and Time Constraints

There are neither resource nor time constraints for theElk Hills A1-A2 storage project. CTV owns the mineral rights, pore space and surface access to the Elk Hills Oil Field.

Wells to be utilized for the project are available, and will be re-purposed. These wells will be accessible for the life of the project and for the post injection monitoring timeframe.

## A.4.Quality Objectives and Criteria

A.4.a. Performance/Measurement Criteria

**Table 3. Summary of Analytical and Field Parameters for Fluid Samples in Tulare Formation water.**

| Parameters | Analytical Methods[1] | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Cations:<br>[List specific cations] | ICP-OEC<br><br>EPA200.7/6010B | 0.05 to 5 mg/L | **15%** | Daily calibration of equipment/CCV/ Blank LCS, MS/MSD/ QC/ICV |
| Anions:<br>[List specific anions] | Ion Chromatography<br>EPA 300.0 | 0.1 to 2 mg/L | **15%** | Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV |
| Dissolved $CO_2$ | SM 4500-CO2-C | 10 mg/L | **NA** | Duplicate analysis |
| Total dissolved solids | SM 2540 C | 10 mg/L | **10%** | Daily balance calibration, duplicates, blanks |
| Alkalinity | SM 2320 B | 10 mg/L | 10% | Duplicate analysis |
| pH (field) | SPA 150.1/SM 4500-H+B | 2 to 12.5pH | 0.2 pH | Daily calibration, duplicates |
| Specific conductance (field) | SM 2510 B | 10 ohms/cm | 1% | Daily calibration, duplicates |
| Temperature (field) | Thermocouple | -5 to 50 C | 0.2 C | Monthly calibration |
| [Dissolved Methane | RSK-175/ Gas Chromatography | NA | NA | Daily calibration/CCV |

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 4. Summary of Analytical Parameters for $CO_2$ Stream.**

| Parameters | Analytical Methods[1] | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Oxygen | ASTM D 1945 | 50 ppmv | 15% | Daily calibration/CCV, blank, QC sample |
| Nitrogen | ASTM D 1945 | 50 ppmv | 15% | Daily calibration/CCV, blank, QC sample |
| Carbon monoxide | ASTM D 1945 | 50 ppmv | 15% | Daily calibration/CCV, blank, QC sample |
| Total hydrocarbons | ASTM D 1945 | 10 ppmv | 15% | Daily calibration/CCV, blank, QC sample |
| Methane | ASTM D 1945 | 10 ppmv | 15% | Daily calibration/CCV, blank, QC sample |
| Hydrogen sulfide | ASTM D 1945/D6228 | 10 ppmv/1 ppmv | 15% | Daily calibration/CCV, blank, QC sample |
| Ethanol | EPA 8260B | 0.5 ppmv | 20% | Daily calibration/CCV, blank, LCS, MS/MSD, ICV |
| $CO_2$ purity | ASTM D 1945 | 50 ppmv | 15% | Daily calibration/CCV, blank, QC sample |
| Total Sulfur | ASTM D 3246 | 1 ppmv | 15% | Daily calibration/CCV, blank, QC sample |

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

**Table 5. Summary of Analytical Parameters for Corrosion Coupons.**

| Parameters | Analytical Methods | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Mass | NACE TM0169/ G31<br>EPA 1110A SW846 | 0.001 mg | 10% | |

**Table 6. Summary of Measurement Parameters for Field Gauges.**

| Parameters | Methods | Detection Limit/Range | Typical Precisions | QC Requirements |
|---|---|---|---|---|
| Booster pump discharge pressure | ANSI Z540-1-1994 | 0.001 / 0 - 5,000 PSI | 0.01 PSI | Annual calibration |
| Injection tubing temperature | ANSI Z540-1-1994 | 0.001 Fahrenheit / 0 – 500 Fahrenheit | 0.01 Fahrenheit | Annual calibration |
| Injection tubing pressure | ANSI Z540-1-1994 | 0.001 / 0 - 5,000 PSI | 0.01 PSI | Annual calibration |
| Annulus pressure | ANSI Z540-1-1994 | 0.001 / 0 - 5,000 PSI | 0.01 PSI | Annual calibration |
| Injection mass flow rate | NA | 0.1 % of flow rate | 0.01 lbs/hour | Annual calibration |

**Table 7. Actionable Testing and Monitoring Outputs.**

| Activity or Parameter | Project Action Limit | Detection Limit | Anticipated Reading |
|---|---|---|---|
| External and internal mechanical integrity (temperature log) | Temperature log indicates a mechanical integrity issue. | 0.01 Fahrenheit | Results will be compared to baseline. Deviation may be indicative of mechanical issue. |
| Surface and downhole pressure | Action will be taken when pressure is outside of expected or modeled range. | 0.001 PSI | No greater than the maximum operating pressure. |
| Water quality (Tulare USDW) | Action will be taken when water sample is outside of baseline analysis. | 0.2 pH | $CO_2$ will decrease the water pH. |
| Above-confining-zone pressure (Etchegoin) | Action will be taken if the pressure of the Etchegoin Formation pressure increases. | 0.001 PSI as per installed pressure gauge. | Reservoir pressure. |

A.4.b. Precision

Field blanks will be collected once per sampling event to assess water sampling analysis accuracy. Service provider will be responsible for analytical precision as per their standard operating procedures.

A.4.c. Bias

Laboratory analysis bias will be assessed and addressed by the individual service provider as per their procedures and methodology.

There is no bias for direct pressure, temperature, and logging measurements.

A.4.d. Representativeness

CTV designed the monitoring network to ensure that samples acquired were representative of site conditions. Standard operating procedures during acquisition at the wellsite will ensure that samples are representative of the formation.

A.4.e. Completeness

Data completeness (amount of data obtained versus the expected data) of 90% for ground water sampling will be acceptable.

Direct measurements, such as pressure and temperature data, will be recorded 90% of the time.

A.4.f. Comparability

Data sets will always be compared to the baseline and previous analysis. Individual threshold changes will be assessed as well as small trend changes.

A.4.g. Method Sensitivity

The following tables provide detail on gauge sensitivities.

**Table 8. Pressure and Temperature—Downhole Gauge Specifications.**

| Parameter | Value |
|---|---|
| Calibrated working pressure range | 0 – 10,000 PSI |
| Initial pressure accuracy | < 2 PSI |
| Pressure resolution | 0.005 PSI |
| Pressure drift stability | < 1 PSI per year |
| Calibrated working temperature range | 77 – 266 degrees Fahrenheit |
| Initial temperature accuracy | < 0.9 Fahrenheit |
| Temperature resolution | 0.009 Fahrenheit |
| Temperature drift stability | 0.1 degrees Fahrenheit per year |
| Max temperature | 302 degrees Fahrenheit |
| Instrument calibration frequency | Annual |

**Table 9. Representative Logging Tool Specifications.**

| Parameter | RST (Pulse Neutron) | CBL |
|---|---|---|
| Logging speed | 200 feet/hour | 1,800 feet/hour |
| Vertical resolution | 15 inches | 6 inches |
| Investigation | Mechanical integrity | Cement bond with casing and formation |
| Temperature rating | 302 Fahrenheit | 350 Fahrenheit |
| Pressure rating | 15,000 PSI | 20,000 PSI |

**Table 10. Pressure Field Gauge.**

| Parameter | Value |
|---|---|
| Calibrated working pressure range | 0 to 3,000 PSI |
| Initial pressure accuracy | < 0.04365 % |
| Pressure resolution | 0.001 PSI |
| Pressure drift stability | 0.125% of upper range limit for 60 months |

**Table 11. Pressure Field Gauge—Injection Tubing Pressure.**

| Parameter | Value |
|---|---|
| Calibrated working pressure range | 0 – 3,000 PSI and 4-20 mA |
| Initial pressure accuracy | <0.03125% |
| Pressure resolution | 0.001 PSI and 0.00001 mA |
| Pressure drift stability | 0.125% of upper range limit for 60 months |

**Table 12. Pressure Field Gauge—Annulus Pressure.**

| Parameter | Value |
|---|---|
| Calibrated working pressure range | 0 to 3,000 PSI |
| Initial pressure accuracy | < 0.025 % |
| Pressure resolution | 0.001 PSI |
| Pressure drift stability | 0.125% of upper range limit for 60 months |

**Table 13. Temperature Field Gauge—Injection Tubing Temperature.**

| Parameter | Value |
|---|---|
| Calibrated working temperature range | 0 to 500 degrees Fahrenheit and 4-20ma |
| Initial temperature accuracy | <0.0055% |
| Temperature resolution | 0.001 degrees Fahrenheit and 0.0001 mA |
| Temperature drift stability | 0.15% of output reading or 0.15 degrees Celsius |

**Table 14. Mass Flow Rate Field Gauge—$CO_2$ Mass Flow Rate.**

| Parameter | Value |
|---|---|
| Calibrated working flow rate range | 0 to 3,000 PSI |
| Initial mass flow rate accuracy | 0.1 % of upper range limit |
| Mass flow rate resolution | 0.1 PSI |
| Mass flow rate drift stability | Estimate <0.3% of output reading for 12 months |

## A.5. Special Training/Certifications

A.5.a. Specialized Training and Certifications

CTV will utilize lab and logging companies to acquire field data samples. All equipment will be provided and operated by the service provider.

A.5.b/c. Training Provider and Responsibility

Training will be provided and assessed by the individual service providers.

### A.6. Documentation and Records

A.6.a. Report Format and Package Information

CTV will prepare and submit semi-annual reports to the EPA. The reports will include all testing, data, and monitoring information as specified in the Testing and Monitoring Plan.

A.6.b. Other Project Documents, Records, and Electronic Files

CTV will prepare and provide all necessary documents, records or electronic files as required.

A.6.c/d. Data Storage and Duration

CTV will maintain the required project data collected in a datastore.

A.6.e. QASP Distribution Responsibility

The project manager will be responsible for ensuring that those on the distribution list, and other essential staff, receive the most current copy of the QASP.

## B. Data Generation and Acquisition

### B.1. Sampling Process Design

B.1.a. Design Strategy

*Shallow Groundwater Monitoring Strategy*

A pre-existing shallow groundwater monitoring well will assess potential changes in the Upper Tulare USDW and Lower Tulare Formation. The Upper Tulare USDW is not a water source in the AoR.

The Upper Tulare Formation USDW is an unconfined aquifer in the AoR. Due to drought conditions, water levels are continuously falling. As such, the 61WS-8R well was selected for the following reasons:

1. It is down gradient and has a thicker section of the Upper Tulare Formation USDW.
2. The well is completed across the Upper Tulare Formation USDW and Lower Tulare Formation. The Lower Tulare is not exempt outside the project area, and any pressure or fluid changes in the Lower Tulare Formation will occur before the Upper Tulare Formation USDW.

CTV will monitor pressure changes associated with the A1-A2 Storage project and fluid analysis.

*Deep Groundwater Monitoring Strategy*

Between the Reef Ridge confining layer and USDW is the Etchegoin Formation. A laterally continuous Etchegoin Formation water sand (3,500 feet TVD) will be pressure monitored for potential $CO_2$ leakage via the 346-7R-RD1 well. The sands have adequate continuity, porosity and permeability to ensure that the AoR is monitored with one well.

Any unlikely leakage from the A1A2 reservoir up through the Reef Ridge confining layer will dissipate in the Etchegoin Formation and increase its pressure.

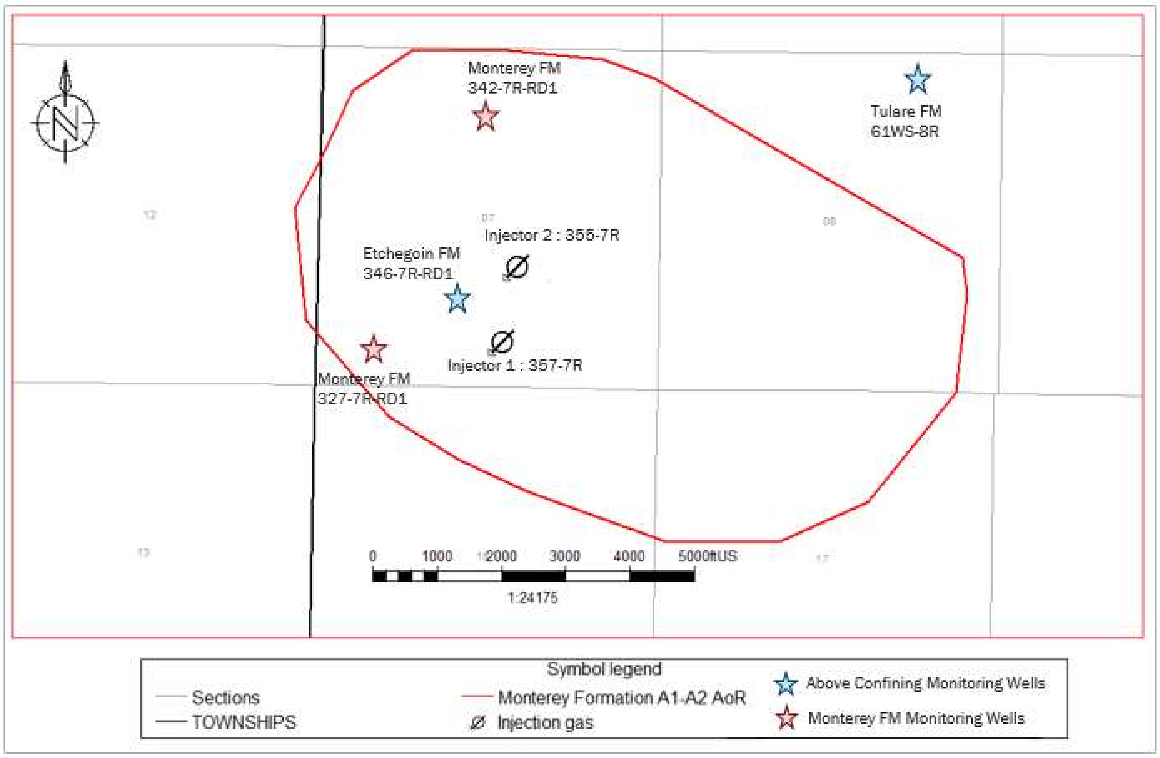
B.1.b. Type and Number of Samples/Test Runs

The sampling activities are summarized in Table 1.

B.1.c. Site/Sampling Locations

Locations for sampling are shown on the map below (Figure 2).

**Figure 2: Monitoring well locations.**




B.1.d. Sampling Site Contingency

CTV owns the mineral rights, pore space and surface access to the storage project.

B.1.e. Activity Schedule

The sampling activities are summarized in Table 1.

B.1.f. Critical/Informational Data

Documentation of information will include the following:

1. Sampling metadata that includes sample label, purging time and other sample collection procedures.
2. Data collected in the field (temperature and pH).
3. Chain of custody.
4. Data and analysis collected in the laboratory.
5. Calibration of Instrumentation and equipment.

B.1.g. Sources of Variability

Potential sources of variability include the following:

1. Natural and operational variability in fluid quality, temperature, and pressure.
2. Reservoir changes from outside the AoR (outside operator, precipitation/drought)
3. Changes in the sampling methods, service provider and instrumentation.

Variability will be minimized by the following:

1. Adhering to standard operating procedures.
2. Assessing data and results against baseline and previous results for trend and changes.
3. Service provider staff training.
4. Assessing calibration and calibrating procedures.
5. Quality control checks for samples.

## B.2. Sampling Methods

B.2.a/b. Sampling SOPs

Refer to the table below for stabilization criteria during well purging.

Laboratory SOPs have been developed by the service provider.

All procedures for sampling shall be consistent with the U.S. Environmental Protection Agency (US EPA) Groundwater Sampling Guidelines for Superfund and RCEAA Project Mangers (May 2002).

**Table 15. Stabilization Criteria of Water Quality Parameters During Shallow Well Purging.**

| Field Parameter | Stabilization Criteria |
|---|---|
| pH | +/- 0.01 |
| Temperature | +/- 1 C |
| Specific conductance | +/- 3% |

B.2.c. In-situ Monitoring

In-situ monitoring of water chemistry is not currently planned.

B.2.d. Continuous Monitoring

Pressure will be collected from monitoring wells.

B.2.e. Sample Homogenization, Composition, Filtration

To obtain a representative sample, each well will be purged at a flow rate between 10 GPM and 5- GPM. Samples will be collected within 24 hours of the well being purged. If a monitoring well will not supply adequate water for sampling, the condition of the well will be investigated and it may be considered for replacement.

Purging will continue until three successive measurements of the indicator parameters meet the stabilization criteria per Table 15.

B.2.f. Sample Containers and Volumes

Sample collection devices will be carefully chosen to minimize the potential for altering the quality of the sample. Teflon and stainless steel are preferred materials, although PVC, HDPE and other similar materials are considered sufficient in some cases.

Refer to the tables below as needed for sample container, preservation, and holding time information.

B.2.g. Sample Preservation

Samples will be preserved as per Table 17.

B.2.h. Cleaning/Decontamination of Sampling Equipment

Equipment used for sampling and other activities associated with on-site work will be de-contaminated before and after performance of a given activity. Disposable items will be disposed of as solid waste in an approved, permitted client facility.

B.2.i. Support Facilities

Support facilities will be provided by the service provider responsible for sampling and analysis.

B.2.j. Corrective Action, Personnel, and Documentation

The service provider will be responsible for testing instruments and equipment and preforming corrective action on defective equipment. Corrective action taken on equipment will be documented.

## B.3. Sample Handling and Custody

B.3.a. Maximum Hold Time/Time Before Retrieval

See Table 16 and 17 for holding times.

B.3.b. Sample Transportation

CTV will ensure that samples are delivered to the laboratory for analysis by the service provider as soon as possible following sample collection. Samples will be transported to the laboratory on the same day as the sample collection.

During transportation, precautions will be implemented to ensure that sample integrity is not affected by extreme temperatures and/or excessive vibration.

Upon arrival at the service provider the samples will be reviewed to ensure the following:

1. The sample arrived intact without container leakage or breakage.

2. Chain of custody documentation and sample labels agree
3. Confirmation that the sample was preserved correctly.

B.3.c. Sampling Documentation

For each test in the field, a worksheet will be compiled for each test interval documenting the procedures and results.

B.3.d. Sample Identification

Samples will be identified with the well location, date sample identification, sampler, and sample type.

**Table 16. Summary of Sample Containers, Preservation Treatments, and Holding Times for $CO_2$ Gas Stream Analysis.**

| Sample | Volume/Container Material | Preservation Technique | Sample Holding time (max) |
|---|---|---|---|
| $CO_2$ gas stream | One-liter tedlar bag | None | 72 hours |

**Table 17. Summary of Anticipated Sample Containers, Preservation Treatments, and Holding Times for Ground Water Samples.**

| Target Parameters | Volume/Container Material | Preservation Technique | Sample Holding Time |
|---|---|---|---|
| Cations:<br>Ca, Fe, Mg, Na, Si, Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Ti | 100 mL plastic | Nitric acid | 180 days |
| Anions:<br>Br, Cl, F $NO_2$ and $SO_4$ | 100 mL plastic | None | 48 hours |
| Dissolved $CO_2$ | 100 ml plastic | None | 14 days |
| Isotopes:<br>Carbon isotope 13 | 100 ml plastic | None | 14 days |
| Alkalinity | 100 mL plastic | None | 14 days |

B.3.e. Sample Chain-of-Custody

Sample transport and handling will be strictly controlled by the service provider field technician to reduce the opportunity for tampered samples. Upon delivery to the laboratory samples will be given unique laboratory sample numbers and recorded in a logbook indicating the client, well number, date, and time of delivery.

## B.4. Analytical Methods

B.4.a. Analytical SOPs

All procedures to sample and analyze groundwater will be consistent with the U.S. Environmental Protection Agency Groundwater Sampling Guidelines for Superfund and RCRA Project Managers (May 2002).

B.4.b. Equipment/Instrumentation Needed

Service providers are expected to provide and utilize the equipment and instruments necessary to perform the required testing and analysis.

Examples of equipment and instrumentation includes safety equipment, sample jars, decontamination supplies, pH meter, EC meters, temperature gauges, and materials to document chain of custody, results, and labels.

B.4.c. Method Performance Criteria

All analytical methods employed by CTV at the A1-A2 Storage project are industry standard and well define. Method performance criteria is not necessary.

B.4.d. Analytical Failure

Service providers conducting analysis are responsible for assessing and addressing analytical failure per their internal procedures and standards.

B.4.e. Sample Disposal

Service providers conducting analysis are responsible for proper sample disposal per internal procedures and standards.

B.4.f. Laboratory Turnaround

Laboratory turnaround times will vary by the analysis being conducted. CTV will communicate to service providers that a 30-day turnaround time for most analysis' is expected.

B.4.g. Method Validation for Nonstandard Methods

All analytical methods employed by CTV at the A1-A2 Storage project are industry standard and well defined. Method performance criteria is not necessary.

## B.5. Quality Control

B.5.a. QC activities

Field quality control may involve the collection of two types of QC blanks, trip, and field blanks, to verify that the sample collection and handling processes have not impaired quality of the final samples.

Trip blank – Trip blanks are prepared for VOC analysis and transported with the empty sample container.

Field Blank- the field blank will be taken in the field to evaluate if certain sampling or cleaning procedures result in cross-contamination of site samples or if atmospheric contamination has occurred.

B.5.b. Exceeding Control Limits

In the case that control limits are exceeded, CTV will review the sampling procedures and results. In the case of a valid test, refer to the Emergency Response Plan for water contamination procedures.

B.5.c. Calculating Applicable QC Statistics

Charge Balance - Solutions must be electrically neutral, the total sum of all the positive charges (cations) must equal the total sum of all negative charges (anions).

$$\text{Charge Balance:} \qquad \sum cations = \sum anions$$

Charge balance error (shown below) will be less than ±5% for acceptable water analyses.

$$CBE = \frac{\sum cations - |\sum anions|}{\sum cations + |\sum anions|} \times 100$$

## B.6. Instrument/Equipment Testing, Inspection, and Maintenance

The service provider will test, inspect, and maintain the instrumentation and equipment used for testing, this will be completed as per the manufacturer's guidelines and the standard operating procedures.

## B.7. Instrument/Equipment Calibration and Frequency

B.7.a. Calibration and Frequency of Calibration

Pressure and temperature gauges will be calibrated according to the manufacturer's recommendations. Calibration certificates will be kept on file.

Lab instrumentation and calibration will be checked weekly to ensure that results are within the control range of parameters.

B.7.b. Calibration Methodology

Instruments will be calibrated for accurate readings. Calibrations will be conducted with individual instrument SOP's and in accordance with the manufacturer's supplied manual for each instrument.

B.7.c. Calibration Resolution and Documentation

Instrument calibration resolution will be consistent with the manufacturer's recommendations. Documentation for instrument calibration will be maintained in a database.

## B.8. Inspection/Acceptance for Supplies and Consumables

B.8.a/b. Supplies, Consumables, and Responsibilities

The service provider responsible for completing sample collection and analysis will be responsible for supplies and consumables.

Supplies and consumables used for sample collection and analysis will be selected to minimize the potential for altering the quality of the sample and analysis results.

## B.9. Nondirect Measurements

B.9.a. Data Sources

Induced seismicity will be monitored continuously to ensure data consistency. CTV will partner with or use a third party to process the data.

B.9.b. Relevance to Project

Passive seismic monitoring will be used to assess induced seismicity events as an indicator of stress changes in the subsurface. Thresholds and response for induced seismic eventsare discussed further in the Emergency Response Plan.

B.9.c. Acceptance Criteria

Industry standard practices will be utilized for data gathering, processing and interpretation.

B.9.d. Resources/Facilities Needed

CTV will use a service provider for all necessary resources and facilities for passive seismic monitoring.

B.9.e. Validity Limits and Operating Conditions

CTV and service provider professionals will ensure that all results and processes are conducted as per standard industry practices.

## B.10. Data Management

B.10.a. Data Management Scheme

CTV will maintain the A1-A2 Storage project data internally. Data will be backed up and held on secure servers.

B.10.b. Recordkeeping and Tracking Practices

All data associated with the project will be held securely and associated meta-data will be gathered and maintained to ensure tracking purposes.

B.10.c. Data Handling Equipment/Procedures

CTV employs robust data management procedures to ensure security of data gathered from the field and external data sources.

B.10.d. Responsibility

Project managers will be responsible for ensuring data management is properly maintained.

B.10.e. Data Archival and Retrieval

CTV will hold all data associated with the A1-A2 Storage project. A data store will be developed for reporting and retrieval.

B.10.f. Hardware and Software Configurations

CTV will ensure that software and hardware are appropriate to integrate the multiple data sources and maintain large quantities of data.

B.10.g. Checklists and Forms

CTV will generate forms, checklists, and procedures as necessary to ensure management, security and quality of all data collected.

# C. Assessment and Oversight

## C.1. Assessments and Response Actions

C.1.a. Activities to be Conducted

Monitoring results will be obtained as per Table 1. Results will be reviewed for QC criteria as per section B.5. In the case of data failure, new samples will be collected and analyzed. Evaluation for data consistency will be performed per the USEPA 2009 Unified Guidance (USEPA, 2009).

C.1.b. Responsibility for Conducting Assessments

CTV will utilize service providers to analyze sample data. These organizations will be responsible for conducting their own internal assessments.

C.1.c. Assessment Reporting

Assessment information will be reported to the project leads as outlined in A.1.

C.1.d. Corrective Action

CTV owns the surface and mineral rights in the Elk Hills Oil Field. Corrective action issues, data collection, and monitoring data will all be handled by CTV.

## C.2. Reports to Management

C.2.a/b. QA status Reports

CTV will notify the EPA and project leaders of QA report status if there are changes to the Testing and Monitoring Plan or the QASP.

# D. Data Validation and Usability

## D.1. Data Review, Verification, and Validation

D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data

Data validation will include the review of the results, chain of custody information, and review of the blank and duplicate information. All results will be stored in a database and compared to baseline and previous results. Data will be graphed to inspect trends and anomalies.

## D.2. Verification and Validation Methods

D.2.a. Data Verification and Validation Processes

Data will be verified by CTV upon receipt of results.

If anomalous data is suspected, CTV and the service provider will review the metadata associated with the sample to assess whether sampling, collection and the analysis conducted caused spurious results. In addition, instrument calibration will be reviewed if necessary.

D.2.b. Data Verification and Validation Responsibility

Data will be verified by CTV upon receipt of results.

D.2.c. Issue Resolution Process and Responsibility

CTV will oversee sample handling and assessment process. CTV management will determine actions necessary to resolve issues.

D.2.d. Checklist, Forms, and Calculations

CTV will develop checklists and a GIS database to store data, complete surveillance and ensure that permit requirements are met.

## D.3. Reconciliation with User Requirements

D.3.a. Evaluation of Data Uncertainty

CTV will develop a GIS database that will be used for surveillance. The database will ensure data quality using methods consistent with USEPA 2009 Unified Guidance.

D.3.b. Data Limitations Reporting

Service provider management will be responsible for ensuring that analysis in their laboratory is presented with data use limitations for reporting.

Project leaders and managers will be responsible for ensuring that results are vetted and evaluated to determine if performance criteria are met.

## References


ASTM, 2005, Method D6517-00 (reapproved 2005), Standard guide for field preservation of groundwater samples, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6564-00 (reapproved 2005), Standard guide for field filtration of ground-water samples, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2005, Method D6452-99 (reapproved 2005), Standard Guide for Purging Methods for Wells Used for Ground-Water Quality Investigations, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

ASTM, 2002, Method D513-11, Standard test methods for total and dissolved carbon dioxide in water, ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA.

U.S. Bureau of Reclamation (USBR), 1995, *Ground Water Manual*, U.S. Dept. of Interior, Bureau of Reclamation, Washington, D.C.

U.S. Environmental Protection Agency (USEPA), 2009, Statistical analysis of groundwater monitoring data at RCRA facilities—Unified Guidance, US EPA, Office of Solid Waste, Washington, DC.

U.S. Environmental Protection Agency (EPA). 1995. Ground Water Sampling - A Workshop Summary. U.S. Environmental Protection Agency, Washington, D.C. EPA/600/R-94/205.

U.S. Environmental Protection Agency (EPA). 1993. Subsurface Characterization and Monitoring Techniques; A Desk Reference Guide. Volume 1: Solids and Ground Water. U.S. Environmental Protection Agency, Washington, D.C. EPA/625/R-93/003a.


## Appendices

Schlumberger Wireline Log Quality Reference Manual

Schlumberger

# Wireline Log Quality Control Reference Manual

Schlumberger

# RST and RSTPro

## Overview

The dual-detector spectrometry system of the through-tubing RST* and RSTPro* reservoir saturation tools enables the recording of carbon and oxygen and Dual-Burst* thermal decay time measurements during the same trip in the well.

The carbon/oxygen (C/O) ratio is used to determine the formation oil saturation independent of the formation water salinity. This calculation is particularly helpful if the water salinity is low or unknown. If the salinity of the formation water is high, the Dual-Burst measurement is used. A combination of both measurements can be used to detect and quantify the presence of injection water of a different salinity from that of the connate water.

## Calibration

The master calibration of the RST and RSTPro tools is conducted annually to eliminate tool-to-tool variation. The tool is positioned within a polypropylene sleeve in a horizontally positioned calibration tank filled with chlorides-free water.

The sigma, WFL* water flow log, and PVL* phase velocity log modes of the RST and RSTPro detectors do not require calibration. The gamma ray detector does not require calibration either.

## Specifications

**Measurement Specifications**

| | RST and RSTPro Tools |
|---|---|
| Output | Inelastic and capture yields of various elements, carbon/oxygen ratio, formation capture cross section (sigma), porosity, borehole holdup, water velocity, phase velocity, SpectroLith* processing |
| Logging speed† | Inelastic mode: 100 ft/h [30 m/h] (formation dependent)<br>Capture mode: 600 ft/h [183 m/h] (formation and salinity dependent)<br>RST sigma mode: 1,800 ft/h [549 m/h]<br>RSTPro sigma mode: 2,800 ft/h [850 m/h] |
| Range of measurement | Porosity: 0 to 60 V/V |
| Vertical resolution | 15 in [38.10 cm] |
| Accuracy | Based on hydrogen index of formation |
| Depth of investigation‡ | Sigma mode: 10 to 16 in [20.5 to 40.6 cm]<br>Inelastic capture (IC) mode: 4 to 6 in [10.2 to 15.2 cm] |
| Mud type or weight limitations | None |
| Combinability | RST tool: Combinable with the PL Flagship* system and CPLT* combinable production logging tool<br>RSTPro tool: Combinable with tools that use the PS Platform* telemetry system and Platform Basic Measurement Sonde (PBMS) |

† See Tool Planner application for advice on logging speed.
‡ Depth of investigation is formation and environment dependent.

**Mechanical Specifications**

| | RST-A and RST-C | RST-B and RST-D |
|---|---|---|
| Temperature rating | 302 degF [150 degC]<br>With flask: 400 degF [204 degC] | 302 degF [150 degC] |
| Pressure rating | 15,000 psi [103 MPa]<br>With flask: 20,000 psi [138 MPa] | 15,000 psi [103 MPa] |
| Borehole size—min. | 1 13/16 in [4.60 cm]<br>With flask: 2¼ in [5.72 cm] | 2⅞ in [7.30 cm] |
| Borehole size—max. | 9⅝ in [24.45 cm]<br>With flask: 9⅝ in [24.45 cm] | 9⅝ in [24.45 cm] |
| Outside diameter | 1.71 in [4.34 cm]<br>With flask: 2.875 in [7.30 cm] | 2.51 in [6.37 cm] |
| Length | 23.0 ft [7.01 m]<br>With flask: 33.6 ft [10.25 m] | 22.2 ft [6.76 m] |
| Weight | 101 lbm [46 kg]<br>With flask: 243 lbm [110 kg] | 208 lbm [94 kg] |
| Tension | 10,000 lbf [44,480 N]<br>With flask: 25,000 lbf [111,250 N] | 10,000 lbf [44,480 N] |
| Compression | 1,000 lbf [4,450 N]<br>With flask: 1,800 lbf [8,010 N] | 1,000 lbf [4,450 N] |

## Tool quality control

### Standard curves

The RST and RSTPro standard curves are listed in Table 1.

**Table 1. RST and RSTPro Standard Curves**

| Output Mnemonic | Output Name |
|---|---|
| BADL_DIAG | Bad level diagnostic |
| CCRA | RST near/far instantaneous count rate |
| COR | Carbon/oxygen ratio |
| CRRA | Near/far count rate ratio |
| CRRR | Count rate regulation ratio |
| DSIG | RST sigma difference |
| FBAC | Multichannel Scaler (MCS) far background |
| FBEF | Far beam effective current |
| FCOR | Far carbon/oxygen ratio |
| FEGF | Far capture gain correction factor |
| FEOF | Far capture offset correction factor |
| FERD | Far capture resolution degradation factor (RDF) |
| FIGF | Far inelastic gain correction |
| FIOF | Far inelastic offset correction factor |
| FIRD | Far inelastic RDF |
| IC | Inelastic capture |
| IRAT_FIL | RST near/far inelastic ratio |
| NBEF | Near beam effective current |
| NCOR | Near carbon/oxygen ratio |
| NEGF | Near capture gain correction factor |
| NEOF | Near capture offset correction factor |
| NERD | Near capture RDF |
| NIGF | Near inelastic gain correction |
| NIOF | Near inelastic offset correction factor |
| NIRD | Near inelastic RDF |
| RSCF_RST | RST selected far count rate |
| RSCN_RST | RST selected near count rate |
| SBNA | Sigma borehole near apparent |
| SFFA_FIL | Sigma formation far apparent |
| SFNA_FIL | Sigma formation near apparent |
| SIGM | Formation sigma |
| SIGM_SIG | Formation sigma uncertainty |
| TRAT_FIL | RST near/far capture ratio |

### Operation

The RST and RSTPro tools should be run eccentered. The main inelastic capture characterization database does not support a centered tool, thus it is important to ensure that the tool is run eccentered. However, for a WFL water flow log, a centered tool is recommended to better evaluate the entire wellbore region.

### Formats

The format in Fig. 1 is used mainly as a hardware quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Track 1
  - CRRA, CRRR, NBEF, and FBEF are shown; FBEF should track openhole porosity when properly scaled.
- Track 6
  - The IC mode gain correction factors measure the distortion of the energy inelastic and elastic spectrum in the near and far detectors relative to laboratory standards. They should read between 0.98 and 1.02.
- Track 7
  - The IC mode offset correction factors are described in terms of gain, offset, and resolution degradation of the inelastic and elastic spectrum in the near and far detectors. They should read between –2 and 2.
- Track 8
  - Distortion on these curves affects inelastic and capture spectra from the near and far detectors. They should be between 0 and 15. Anything above 15 indicates a tool problem or a tool that is too hot (above 302 degF [150 degC]), which affects yield processing.

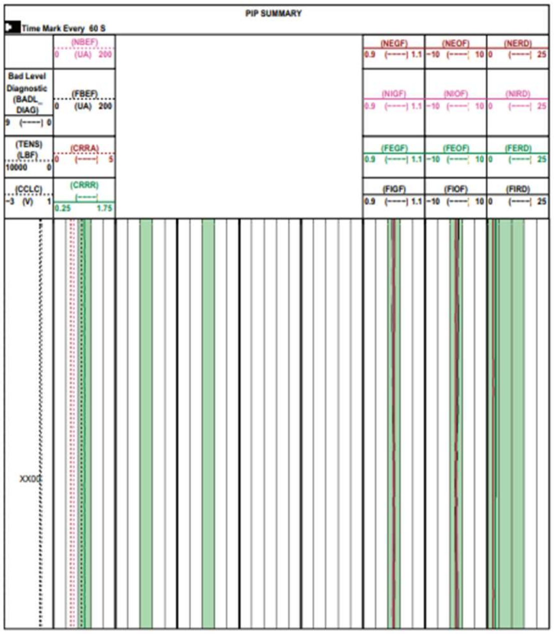


Figure 1. RST and RSTPro hardware format.

The format in Fig. 2 is used mainly for sigma quality control.

- Depth track
  - Deflection of the BADL_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).
- Tracks 2 and 3
  - The IRAT_FIL inelastic ratio increases in gas and decreases with porosity.
  - DSIG in a characterized completion should equal approximately zero. Departures from zero indicate either the environmental parameters are set incorrectly or environment is different from the characterization database (e.g., casing is not fully centered in the wellbore or the tool is not eccentered). Shales typically read 1 to 4 units from the baseline of zero because they are not characterized in the database.

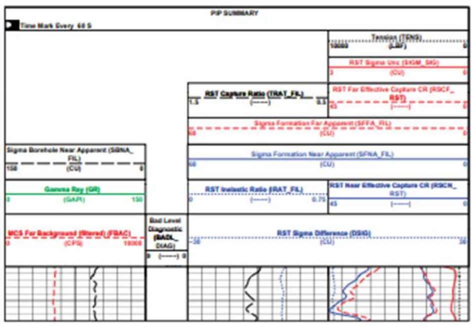


*Figure 2. RST and RSTPro sigma standard format.*

## Response in known conditions

In front of a clean water zone, COR is smaller than the value logged across an oil zone. Oil in the borehole affects both the near and far COR, causing them to read higher than in a water-filled borehole. In front of shale, high COR is associated with organic content.

The computed yields indicate contributions from the materials being measured (Table 2).

**Table 2. Contributing Materials to RST and RSTPro Yields**

| Element | Contributing Material |
|---|---|
| C and O | Matrix, borehole fluid, formation fluid |
| Si | Sandstone matrix, shale, cement behind casing |
| Ca | Carbonates, cement |
| Fe | Casing, tool housing |

Bad cement quality affects readings (Table 3). A water-filled gap in the cement behind the casing appears as water to the IC measurement. Conversely, an oil-filled gap behind the casing appears as oil to the IC measurement.

**Table 3. RST and RSTPro Capture and Sigma Modes**

| Medium | Sigma, cu |
|---|---|
| Oil | 18 to 22 |
| Gas | 0 to 12 |
| Water, fresh | 20 to 22 |
| Water, saline | 22 to 120 |
| Matrix | 8 to 12 |
| Shale | 35 to 55 |

Schlumberger

# Cement Bond Tool

## Overview

The cement bond log (CBL) made with the Cement Bond Tool (CBT) provides continuous measurement of the attenuation of sound pulses, independent of casing fluid and transducer sensitivity. The tool is self-calibrating and less sensitive to eccentering and sonde tilt than the traditional single-spacing CBL tools. The CBT additionally gives the attenuation of sound pulses from a receiver spaced 0.8 ft [0.24 m] from the transmitter, which is used to aid interpretation in fast formations.

A CBL curve computed from the three attenuations available enables comparison with CBLs based on the typical 3-ft [0.91-m] spacing. This computed CBL continuously discriminates between the three attenuations to choose the one best suited to the well conditions. An interval transit-time curve for the casing is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. This display provides information on the cement/formation bond and other factors that are important to the interpretation of cement quality.

## Specifications

| Measurement Specifications | |
|---|---|
| Output | Attenuation measurement, CBL, VDL image, transit times |
| Logging speed | 1,800 ft/h [549 m/h]† |
| Range of measurement | Formation and casing dependent |
| Vertical resolution | CBL: 3 ft [0.91 m]<br>VDL: 5 ft [1.52 m]<br>Cement map: 2 ft [0.61 m] |
| Accuracy | Formation and casing dependent |
| Depth of investigation | CBL: casing and cement interface<br>VDL: depends on bonding and formation |
| Mud type or weight limitations | None |

† Speed can be reduced depending on data quality.

| Measurement Specifications | |
|---|---|
| Temperature rating | 350 degF [177 degC] |
| Pressure rating | 20,000 psi [138 MPa] |
| Borehole size—min. | 3.375 in [8.57cm] |
| Borehole size—max. | 13.375 in [33.97 cm] |
| Outside diameter | 2.75 in [6.985 cm] |
| Weight | 309 lbm [140 kg] |

## Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

## Tool quality control

### Standard curves

CBT standard curves are listed in Table 1.

**Table 1. CBT Standard Curves**

| Output Mnemonic | Output Name |
|---|---|
| CCL | Casing collar locator amplitude |
| DATN | Discriminated BHC attenuation |
| DBI | Discriminated bond index |
| DCBL | Discriminated synthetic CBL |
| DT | Interval transit time of casing (delta-*t*) |
| DTMD | Delta-*t* mud (mud slowness) |
| GR | Gamma ray |
| NATN | Near 2.4-ft attenuation |
| NBI | Near bond index |
| NCBL | Near synthetic CBL |
| R32R | Ratio of receiver 3 sensitivity to receiver 2 sensitivity, dB |
| SATN | Short 0.8-ft attenuation† |
| SB1 | Short bond index† |
| SCBL | Short synthetic CBL† |
| TT1 | Transit time for mode 1 (upper transmitter, receiver 3 [UT-R3]) |
| TT2 | Transit time for mode 2 (UT-R2) |
| TT3 | Transit time for mode 3 (lower transmitter, receiver 2 [LT-R2]) |
| TT4 | Transit time for mode 4 (LT-R3) |
| TT6 | Transit time for mode 6 (UT-R1) |
| ULTR | Ratio of upper transmitter output strength to the lower transmitter output strength |
| VDL | Variable Density log |

† In fast formations only

## Operation

The tool should be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

## Formats

The format in Fig. 1 is used both as an acquisition and quality control format.

- Track 1
  - DT and DTMD are derived from the transit-time measurements from all transmitter-receiver pairs. They respond to eccentralization of any of the six measurements modes and are a sensitive indicator of wellbore conditions. In a low-quality cement bond or free pipe, both readings are correct. In well-bonded sections, the transit time may cycle skip, affecting the DT and DTMD values.
  - CCL deflects in front of casing collars.
  - GR is used for correlation purposes.
- Track 2
  - DCBL is related to casing size, casing weight, and mud. As a quality control DCBL should be checked against the expected responses in known conditions (see the following section). Also, DCBL should match the VDL image readings.
- Track 3
  - VDL is a map of the waveform amplitude versus depth and it should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings. For example, in a free-pipe section, the DCBL amplitude reads high and VDL shows strong casing arrivals with no formation arrivals. In a zone of good bond for the casing to the formation, the CBL amplitude reads low and the VDL has weak casing arrivals and clear formation arrivals.

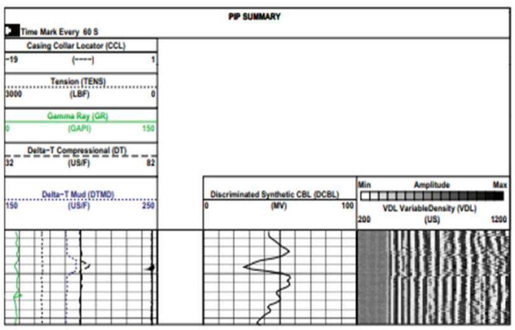



*Figure 1. CBT standard format for CBL and VDL.*

The format in Fig. 2 is also used both as an acquisition and quality control format.

- Track 1
  - The transit time pairs should overlay (TT1C overlays TT3C, and TT2C overlays TT4C) because these pairs are derived from equivalent transmitter-receiver spacings. In very good cement sections, the transit-time curve may be affected by cycle skipping. DT and DTMD may be also affected.
- Track 2
  - The ULTR and R32R ratios are quality indicators of the transmitter or receiver strengths. They should be 0 dB ± 3 dB, unless one of the transmitters or receivers is weak. Both curves should be checked for consistency and stability.
- Track 3
  - DATN should equal NATN in free-pipe sections. In the presence of cement behind casing and in normal conditions, NATN reads higher than DATN.
- Track 4
  - VDL is a map of the waveform amplitude versus depth that should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings.

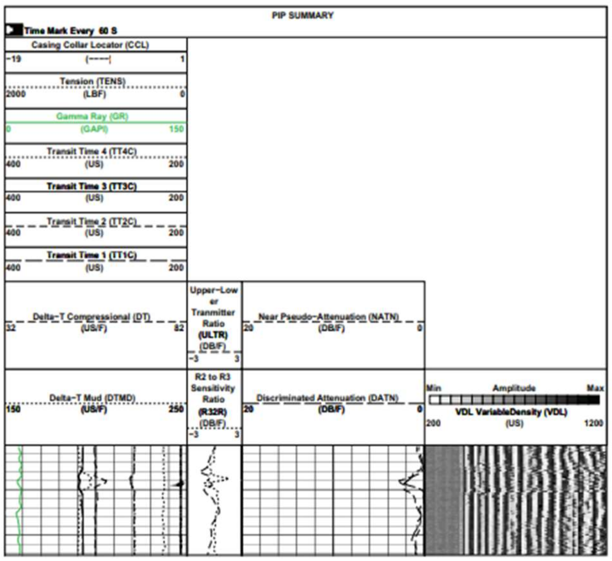



*Figure 2. Additional CBT standard format for CBL and VDL.*

### Response in known conditions

- DT in casing should read the value for steel (57 us/ft ± 2 us/ft [187 us/m ± 6.6 us/m]).
- DTMD should be compared with known velocities (water-base mud: 180–200 us/ft [590–656 us/m], oil-base mud: 210–280 us/ft [689–919 us/m]).
- Typical responses for different casing sizes and weights are listed in Table 2.

**Table 2. Typical CBT Response in Known Conditions**

| Casing Size, in | Casing Weight, lbm/ft | DCBL in Free Pipe, mV | TT1, us | TT2, us | TT5, us |
|---|---|---|---|---|---|
| 4.5 | 11.6 | 84 ± 8 | 252 | 195 | 104 |
| 5 | 13 | 77 ± 7 | 259 | 203 | 112 |
| 5.5 | 17 | 71 ± 7 | 267 | 210 | 120 |
| 7 | 24 | 61 ± 6 | 290 | 233 | 140 |
| 8.625 | 38 | 55 ± 6 | 314 | 257 | 166 |
| 9.625 | 40[†] | 52 ± 5 | 329 | 272 | NM[‡] |

[†] Although the CBT operates in up to 13⅜-in casing, the VDL presentation mainly shows casing arrivals where casings of 9⅝ in and larger are logged.
[‡] NM = not meaningful

Schlumberger

# Cement Bond Logging

## Overview

Cement bond tools measure the bond between the casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools. In the case of sonic tools, the measurement is usually displayed on a cement bond log (CBL) in millivolt units, decibel attenuation, or both. Reduction of the reading in millivolts or increase of the decibel attenuation is an indication of better-quality bonding of the cement behind the casing to the casing wall. Factors that affect the quality of the cement bonding are

- cement job design and execution as well as effective mud removal
- compressive strength of the cement in place
- temperature and pressure changes applied to the casing after cementing
- epoxy resin applied to the outer wall of the casing.

The recorded CBL provides a continuous measurement of the amplitude of sound pulses produced by a transmitter-receiver pair spaced 3-ft [0.91-m] apart. This amplitude is at a maximum in uncemented free pipe and minimized in well-cemented casing. A transit-time (TT) curve of the waveform first arrival is also recorded for interpretation and quality control.

A Variable Density* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. The VDL display provides information on the cement quality and cement/formation bond.

## Specifications

**Measurement Specifications**

| | Digital Sonic Logging Tool (DSLT) and Hostile Environment Sonic Logging Tool (HSLT) with Borehole-Compensated (BHC) | Slim Array Sonic Tool (SSLT) and SlimXtreme* Sonic Logging Tool (QSLT) |
|---|---|---|
| Output | SLS-C, SLS-D, SLS-W, and SLS-E:[†]<br>3-ft [0.91-m] CBL<br>Variable Density waveforms | 3-ft [0.91-m] CBL and attenuation<br>1-ft [0.30-m] attenuation<br>5-ft [1.52-m] Variable Density waveforms |
| Logging speed | 3,600 ft/h [1,097 m/h] | 3,600 ft/h [1,097 m/h] |
| Range of measurement | 40 to 200 us/ft [131 to 656 us/m] | 40 to 400 us/ft [131 to 1,312 us/m] |
| Vertical resolution | Amplitude (mV): 3 ft [0.91 m]<br>VDL: 5 ft [1.52 m] | Near attenuation: 1 ft [0.30 m]<br>Amplitude (mV): 3 ft [0.91 m]<br>VDL: 5 ft [1.52 m] |
| Depth of investigation | Synthetic CBL from discriminated attenuation (DCBL): Casing and cement interface<br>VDL: Depends on cement bonding and formation properties | DCBL: Casing and cement interface<br>VDL: Depends on cement bonding and formation properties |
| Mud type or weight limitations | None | None |
| Special applications | | Conveyed on wireline, drillpipe, or coiled tubing<br>Logging through drillpipe and tubing, in small casings, fast formations |

[†] The DSLT uses the Sonic Logging Sonde (SLS) to measure cement bond amplitude and VDL evaluation.

| Mechanical Specifications | | | | |
|---|---|---|---|---|
| | **DSLT** | **HSLT** | **SSLT** | **QSLT** |
| Temperature rating | 302 degF [150 degC] | 500 degF [260 degC] | 302 degF [150 degC] | 500 degF [260 degC] |
| Pressure rating | 20,000 psi [138 MPa] | 25,000 psi [172 MPa] | 14,000 psi [97 MPa] | 30,000 psi [207 MPa] |
| Casing ID—min. | 5 in [12.70 cm] | 5 in [12.70 cm] | 3½ in [8.89 cm] | 4 in [10.16 cm] |
| Casing ID—max. | 18 in [45.72 cm] | 18 in [45.72 cm] | 8 in [20.32 cm] | 8 in [20.32 cm] |
| Outside diameter | 3⅝ in [9.21 cm] | 3¾ in [9.53 cm] | 2½ in [6.35 cm] | 3 in [7.62 cm] |
| Length | SLS-C and SLS-D: 18.7 ft [5.71 m]<br>SLS-E and SLS-W: 20.6 ft [6.23 m] | With HSLS-W sonde:<br>25.5 ft [7.77 m] | 23.1 ft [7.04 m]<br>With inline centralizers:<br>29.6 ft [9.02 m] | 23 ft [7.01 m]<br>With inline centralizers:<br>29.9 ft [9.11 m] |
| Weight | SLS-C and SLS-D: 273 lbm [124 kg]<br>SLS-E and SLS-W: 313 lbm [142 kg] | With HSLS-W sonde:<br>440 lbm [199 kg] | 232 lbm [105 kg]<br>With inline centralizers:<br>300 lbm [136 kg] | 295 lbm [134 kg]<br>With inline centralizers:<br>407 lbm [185 kg] |
| Tension | 29,700 lbf [132,110 N] | 29,700 lbf [132,110 N] | 13,000 lbf [57,830 N] | 13,000 lbf [57,830 N] |
| Compression | SLS-C and SLS-D:<br>1,700 lbf [7,560 N]<br>SLS-E and SLS-W:<br>2,870 lbf [12,770 N] | With HSLS-W sonde:<br>2,870 lbf [12,770 N] | 4,400 lbf [19,570 N] | 4,400 lbf [19,570 N] |

## Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Scheduled frequency of Q-checks varies for each tool. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

## Tool quality control

### Standard curves

CBL standard curves are listed in Table 1.

**Table 1. CBL Standard Curves**

| Output Mnemonic | Output Name |
|---|---|
| BI | Bond index |
| CBL | Cement bond log (fixed gate) |
| CBLF | Fluid-compensated cement bond log |
| CBSL | Cement bond log (sliding gate) |
| CCL | Casing collar log |
| GR | Gamma ray |
| TT | Transit time (fixed gate) |
| TTSL | Transit time (sliding gate) |
| VDL | Variable Density log |

### Operation

The tool must be run centralized.

A log should be made in a free-pipe zone (if available). Where a micro-annulus is suspected, a repeat section should be made with pressure applied to the casing.

### Formats

The format in Fig. 1 is used for both acquisition and quality control.

- Track 1
  - TT and TTSL should be constant through the log interval and should overlay. These curves deflect near casing collars. In sections of very good cement, the signal amplitude is low; detection may be affected by cycle skipping. GR is used for correlation purposes, and CCL serves as a reference for future cased hole correlations..
- Track 2
  - CBL measured in millivolts from the fixed gate should be equal to CBSL measured from the sliding gate, except in cases of cycle skipping or detection on noise.
- Track 3
  - VDL is a presentation of the acoustic waveform at a receiver of a sonic measurement. The amplitude is presented in shades of a gray scale. The VDL should show good contrast. In free pipe, it should be straight lines with chevron patterns at the casing collars. In a good bond, it should be gray (low amplitudes) or show strong formation signals (wavy lines).

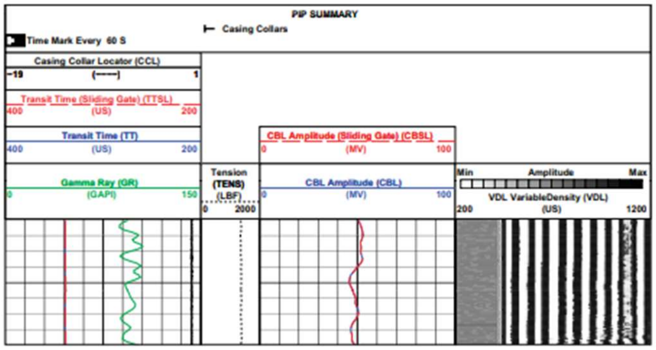



*Figure 1. DSLT standard format.*

## Response in known conditions

The responses in Table 2 are for clean, free casing.

**Table 2. Typical CBL Response in Known Conditions**

| Casing OD, in | Weight, lbm/ft | Nominal Casing ID, in | CBL Amplitude Response in Free Pipe, mV |
|---|---|---|---|
| 5 | 13 | 4.494 | 77 ± 8 |
| 5.5 | 17 | 4.892 | 71 ± 7 |
| 7 | 23 | 6.366 | 62 ± 6 |
| 8.625 | 36 | 7.825 | 55 ± 6 |
| 9.625 | 47 | 8.681 | 52 ± 5 |
| 10.75 | 51 | 9.850 | 49 ± 5 |
| 13.375 | 61 | 12.515 | 43 ± 4 |
| 18.625 | 87.5 | 17.755 | 35 ± 4 |

# ATTACHMENT C: TESTING AND MONITORING PLAN
# 40 CFR 146.90

## Elk Hills A1-A2 Storage Project

**Facility Information**

| | |
|---|---|
| Facility name: | Elk Hills A1-A2 Storage<br>357-7R |
| Facility contact: | Kenneth Haney / CCS Project Manager<br>28590 Highway 119<br><br>Tupman, CA 93276<br>(661) 763-6101/ Kenneth.Haney@CTV.com |
| Well location: | Elk Hills Oil Field, Kern County, CA<br>35.32802963 / -119.5449982 |

This Testing and Monitoring Plan describes how Carbon TerraVault 1 LLC (CTV) will monitor the Elk Hills A1-A2 Storage site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the well is operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the $CO_2$ within the storage zone, supporting AoR re-evaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

### *Quality assurance procedures*

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

### *Reporting procedures*

CTV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

## Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV will analyze the $CO_2$ stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the date of authorization of injection and every three months thereafter.

CTV is evaluating several sources of $CO_2$ as injectate for the project. Notification will be sent to the EPA prior to switching or adding $CO_2$ sources, at which time the sampling procedures can be reassessed.

### *Sampling location and frequency*

$CO_2$ injectate samples will be taken between the final compression stage and the wellhead. Sampling will take place three months after the date of authorization of injection and every three months thereafter.

CTV will increase the frequency and collect additional samples if the following occurs:

1. Significant changes in the chemical or physical characteristics of the $CO_2$ injectate, such as a change in the $CO_2$ injectate source; and
2. Facility or injector downtime is greater than thirty days.

### *Analytical parameters*

CTV will analyze the $CO_2$ for the constituents identified in Table 1 using the methods listed.

**Table 1. Summary of analytical parameters for $CO_2$ stream.**

| Parameter | Analytical Method(s) |
|---|---|
| Oxygen | ASTM D1945 |
| Nitrogen | ASTM D1945 |
| Carbon Monoxide | ASTM D1945 |
| Total hydrocarbons | ASTM D1945 |
| Methane | ASTM D1945 |
| Hydrogen Sulfide | ASTM D1945/D6228 |
| $CO_2$ purity | ASTM D1945 |
| Total Sulfur | ASTM 3246 |

***Sampling methods***

$CO_2$ stream sampling will occur in the last compressor station prior to being sent to the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

***Laboratory to be used/chain of custody and analysis procedures***

Samples will be sent to, and analysis conducted by, Zalco Laboratory (Zalco).

Zalco is a full-service laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Zalco has a chain of custody procedure that includes the following;

1. Sample date.
2. Sample description.
3. Sample type.
4. Relinquished by and received by signature.
5. Sampler name.
6. Location information.

**Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]**

CTV will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the $CO_2$ stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

***Monitoring location and frequency***

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table.

All monitoring will be continuous with a 30 second sampling and recording frequency for both active and shut-in periods.

**Table 2. Sampling devices, locations, and frequencies for continuous monitoring.**

| Parameter | Device(s) | Location | Min. Sampling Frequency | Min. Recording Frequency |
|---|---|---|---|---|
| Injection pressure | Pressure Gauge | Surface and Downhole | 30 seconds | 30 seconds |
| Injection rate | Flowmeter | Surface | 30 seconds | 30 seconds |
| Injection volume | Calculated | Surface | 30 seconds | 30 seconds |
| Annular pressure | Pressure Gauge | Surface | 30 seconds | 30 seconds |
| $CO_2$ stream temperature | Temperature gauge | Surface and Downhole | 30 seconds | 30 seconds |

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

***Monitoring details***

### Injection Rate and Pressure Monitoring

Injection pressure (gauge), temperature (gauge) and flow rate (flow meter) will be continuously and monitored by the Elk Hills Central Command Facility (CCF). Injection rate and pressure limitations will be implemented to ensure adherence to the maximum allowable injection pressure of 90% of the injection zone's fracture pressure.

Pressure and temperature gauges will be calibrated as shown in QASP Table 6.

**Calculation of Injection Volumes**

The volume of $CO_2$ injected into the Monterey Formation A1-A2 will be calculated from the injection flow rate and $CO_2$ density. Density will be determined from the Massachusetts Institute of Technology's $CO_2$ Thermophysical Calculator.

https://sequestration.mit.edu/tools/index.html

**Annular Pressure Monitoring**

Annulus pressure is monitored continuously to ensure integrity of the down-hole packer and tubing. Pressure will be read at the surface via a pressure gauge. The annulus will be filled with a non-corrosive fluid. Any deviations in the annular pressure may indicate a well integrity issue that will be investigated.

**Casing-tubing Pressure**

CTV will monitor the casing-tubing pressure continuously (every 30 seconds) via a pressure gauge. The surface pressure of the casing-tubing annulus will be between 0 and 800 PSI.

**Injection Rate**

The injection rate will be monitored with a Coriolis flowmeter. The meter will be calibrated for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent.

## Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), CTV will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

***Monitoring location and frequency***

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7).

CTV will continually update the corrosion monitoring plan as data is acquired.

***Sample description***

Samples of the materials used in the construction of the pipeline, and injection well that are exposed to $CO_2$ injectate will be monitored for corrosion using corrosion coupons. Representative materials (Table 3) will be weighed, measured, and photographed prior to installation.

**Table 3. List of equipment coupon with material of construction.**

| Equipment Coupon | Material of Construction |
|---|---|
| Pipeline | CS A106B |
| Casing | N80 Steel |
| Tubing | 13 CR-95 |
| Wellhead | Stainless steel |

***Monitoring details***

The corrosion coupons will be located in the pipeline that feeds $CO_2$ injectate to the injectors. Every six months the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram.

A corrosion rate of greater than 0.3 mils/year will initiate consultation with the regulatory agencies. In addition, a casing inspection log may be run to assess the thickness and quality of the casing if the corrosion rate exceeds 0.3 mils/year.

## Above Confining Zone Monitoring

CTV will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d).

Monitoring above the confining zone will include the following:

1. Tulare Formation - Tulare Formation that includes the Upper Tulare Formation USDW and Lower Tulare Formation will be monitored from 1,017 – 1,950 feet TVD (- 399 to - 1332 feet TVDSS).

2. Etchegoin Formation – between the confining layer and USDW at 3,828 feet TVD (-3,091 feet TVDSS).

***Monitoring location and frequency***

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well locations with respect to the AoR. The wells are located within the Elk Hills Oil Field, CTV owns the surface and mineral rights.

Etchegoin Formation

The Etchegoin Formation zone between the confining zone and Upper Tulare USDW will dissipate any $CO_2$ injectate that migrates upward through the confining zone. The Etchegoin will be monitored continuously for pressure and temperature changes within a continuous sand at –3,091 feet SSTVD. Leakage from the Monterey Formation to the Etchegoin Formation will increase the reservoir pressure and decrease the temperature of the Etchegoin.

The 346-7R-RD1 Etchegoin monitor well is located between the two $CO_2$ injection wells (Figure 1). The Etchegoin zone is continuous across the AoR. As such, 346-7R-RD1 will adequately monitor for pressure and temperature changes.

Prior to injection, baseline water analysis will be acquired for the Etchegoin Formation monitoring zone.

<u>Tulare Formation</u>

Monitoring in the Upper Tulare will include pressure and fluid sampling. Leakage to the Tulare Formation would increase the reservoir pressure and change the composition of the formation water (increased $CO_2$ concentration).

Along with the Upper Tulare aquifer, CTV will monitor the Lower Tulare in well 61WS-8R due to the following:

1. Within the AoR, the liquid column in the Upper Tulare is very thin. It is dependent on regional aquifer recharge and due to drought, the water level is falling. The down-dip 61WS-8R monitoring well location will have a thicker section of Upper Tulare USDW water to be sampled.

2. The Lower Tulare is not considered an exempt aquifer outside the project area. The monitoring well will validate that the Lower Tulare is not impacted by $CO_2$.

CTV has obtained a baseline analysis for the 61WS-8R well. Prior to injection, an updated baseline analysis will be completed. Future results will be compared against these baseline results for significant changes or anomalies. In particular, pH will be monitored as a key indicator of $CO_2$ presence.

Additional groundwater monitoring wells will be drilled to assess and monitor the Upper Tulare USDW if the following occurs:

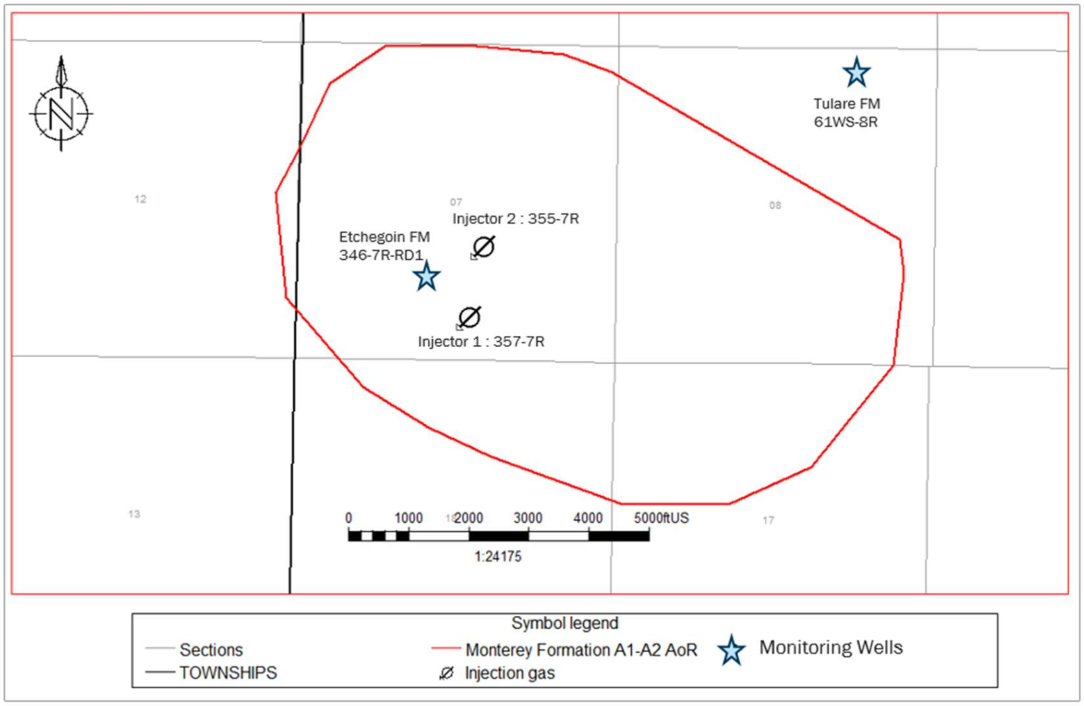
1. Etchegoin Formation monitoring well indicates increased pressure due to Monterey Formation A1-A2 $CO_2$ injection.

2. Tulare Formation pressure or composition changes due to Monterey Formation A1-A2 $CO_2$ injection.

**Table 4. Monitoring of ground water quality and geochemical changes above the confining zone.**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Frequency |
|---|---|---|---|
| Tulare Formation | Fluid Sampling | 61WS-8R | Annually |
| | Pressure/Temperature | 61WS-8R | Continuously |
| Etchegoin Formation | Pressure/Temperature | 346-7R-RD1 | Continuously |

**Figure 1: Above confining zone monitoring wells.**




### *Analytical parameters*

Table 5 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

**Table 5. Summary of analytical and field parameters for ground water samples.**

| Parameters | Analytical Methods |
|---|---|
| **Tulare Formation** | |
| Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Tl) | ICP-OEC<br>EPA 200.7/6010B |
| Cations (Ca, Fe, K, Mg, Na, Si) | ICP-OEC<br>EPA 200.7/6010B |
| Anions (Br, Ca, F, NO3, SO4) | Ion Chromatography, EPA Method 300.0 |
| Dissolved $CO_2$ | SM 4500-CO2-C |
| Total Dissolved Solids | SM 2540 C |
| Alkalinity | SM 2320 B |
| pH (field) | EPA 150.1 / SM4500-H+B |
| Specific Conductance (field) | SM 2510 B |
| Temperature (field) | Thermocouple |
| Dissolved Methane | RSK-175/Gas<br>Chromatography |

***Sampling methods***

Samples will be collected using the following procedures:

1. Depth and elevation measurements for water level taken.
2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
4. Samples preserved and sent to lab as per chain of custody procedure.
5. Closure of well.

***Laboratory to be used/chain of custody procedures***

Samples will be sent to, and analysis conducted by Zalco, a full-service laboratory in Bakersfield, 20 miles from the Elk Hills A1-A2 Storage site. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Zalco has a chain of custody procedure that includes the following;

1. Sample date
2. Sample description
3. Sample type
4. Relinquished by and received by signature
5. Sampler name
6. Location information

**<u>External Mechanical Integrity Testing</u>**

CTV will conduct at least one test periodically during the injection phase to verify external mechanical integrity as required at 146.89(c) and 146.90. MITs will be performed annually, within 30 days of the injection authorization date.

CTV will run a temperature log via wireline to ensure mechanical integrity of the tubing and downhole packer. If CTV elects to conduct an alternate MIT, notification that includes the test and a description will be sent to the EPA for approval.

### *Testing location and frequency*

**Table 6. MITs.**

| **Test Description** | **Location** |
|---|---|
| Temperature Log | Along wellbore via wireline well log |
| Radioactive Tracer | Along wellbore via iodine |

### *Testing details*

CTV will follow the following procedures for MIT temperature logging:

1. Stabilize injection for 24 hours prior to running the temperature log. If possible, the wireline speed will be limited to 20 feet per minute or less.
2. Run a temperature survey from 200 feet above the Reef Ridge Shale base to the deepest point reachable in the well, while injecting at a rate that allows for safe operations.
3. Shut-in well and run multiple temperature surveys with 1-2 hours between runs.
4. Assess the acquired time lapse temperature profiles. As the well cools, the temperature profile is compared to the baseline. External integrity issues present themselves anomalies when compared to the baseline.

## Pressure Fall-Off Testing

CTV will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

### *Testing location and frequency*

The main benefit of pressure fall-off testing is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV does not currently plan to complete pressure fall off testing. The Monterey Formation A1-A2 reservoir is a depleted oil and gas reservoir with known reservoir continuity, boundaries, and flow properties from decades of water and gas injection. CTV may address scaling through time by acidizing the well to clean out the perforations.

CTV will consider pressure fall-off testing if injection rate decreases, with a simultaneous injection pressure increase outside the results from computational modeling.

### *Testing details*

If CTV completes a pressure fall-off test, the following procedure will be followed:

1. Injection rate will be held constant prior to shut-in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.
2. Upon shutting-in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.
3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

Pressure sensors used for this test will be the wellhead gauges and a downhole gauge for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

## Carbon Dioxide Plume and Pressure Front Tracking

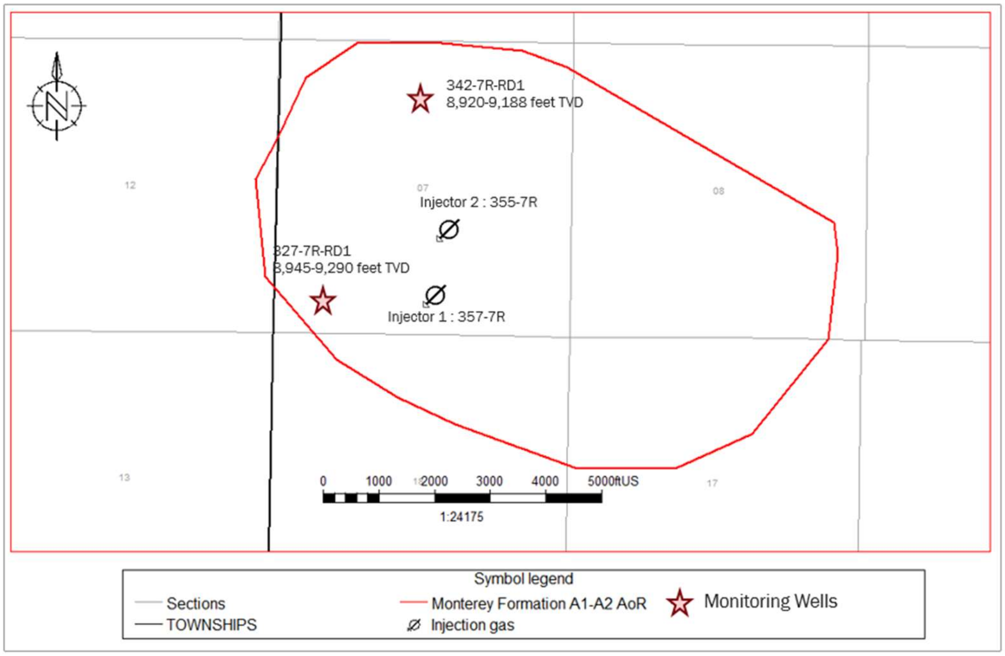
CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

### *Plume monitoring location and frequency*

Table 7 presents the methods that CTV will use to monitor the position of the $CO_2$ plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 8. Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND AQUISTION of the QASP.

Figure 2 shows the location and depth of the wells that will monitor the $CO_2$ plume directly in the targeted A1-A2 zone. These wells will actively monitor the development of the $CO_2$ plume upon the initiation of injection. If the plume development is not consistent with computation modeling results, CTV will assess whether additional monitoring of the plume is necessary.

**Figure 2: Monterey Formation A1-A2 sequestration reservoir monitoring wells, with true vertical depth in feet of the monitoring interval.**




### *Plume monitoring details*

Fluid sampling and pressure monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the $CO_2$ content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 8.

As discussed in the AoR and Corrective Action Plan, 98% of the post-shut-in injected $CO_2$ will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved $CO_2$, and water density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand $CO_2$ saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every two years during the injection phase.

Underlying Monterey A3-A11 Reservoir Monitoring

CTV will monitor the Monterey Formation A3-A11 reservoir and wellbores for $CO_2$ migration. Waterflood producers will be monitored via fluid sampling once per quarter for changes in composition. In addition, Monterey Formation A3-A11 waterflood injectors will have MITs and SAPTs to ensure internal and external mechanical integrity. This monitoring will be discussed in more detail within the Testing and Monitoring Plan. Additionally, due to its waterflood infrastructure and high reservoir pressure, the A3-A6 reservoir is considered a viable future target for $CO_2$ miscible enhanced oil recovery.

**Table 7. Plume monitoring activities.**

| | | | |
|---|---|---|---|
| **DIRECT PLUME MONITORING** | | | |
| Monterey Formation A1-A2 | Fluid Sampling | 327-7R-RD1 and 342-7R-RD1 | Annual |
| Monterey Formation A3+ | Fluid Sampling | EOR producers | Quarterly |
| **INDIRECT PLUME MONITORING** | | | |
| Monterey Formation A1-A2 | Pulse Neutron Logging | 327-7R-RD1 and 342-7R-RD1 | Every two years from start of injection. |

**Table 8. Summary of analytical and field parameters for fluid sampling in the injection zone.**

| Parameters | Analytical Methods |
|---|---|
| **Tulare Formation** | |
| Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Tl) | ICP-OEC<br>EPA 200.7/6010B |
| Cations (Ca, Fe, K, Mg, Na, Si) | ICP-OEC<br>EPA 200.7/6010B |
| Anions (Br, Ca, F, NO3, SO4) | Ion Chromatography, EPA Method 300.0 |
| Dissolved CO2 | SM 4500-CO2-C |
| Total Dissolved Solids | SM 2540 C |
| Alkalinity | SM 2320 B |
| pH (field) | EPA 150.1 / SM4500-H+B |
| Specific Conductance (field) | SM 2510 B |
| Temperature (field) | Thermocouple |
| Dissolved Methane | RSK-175/Gas<br>Chromatography |

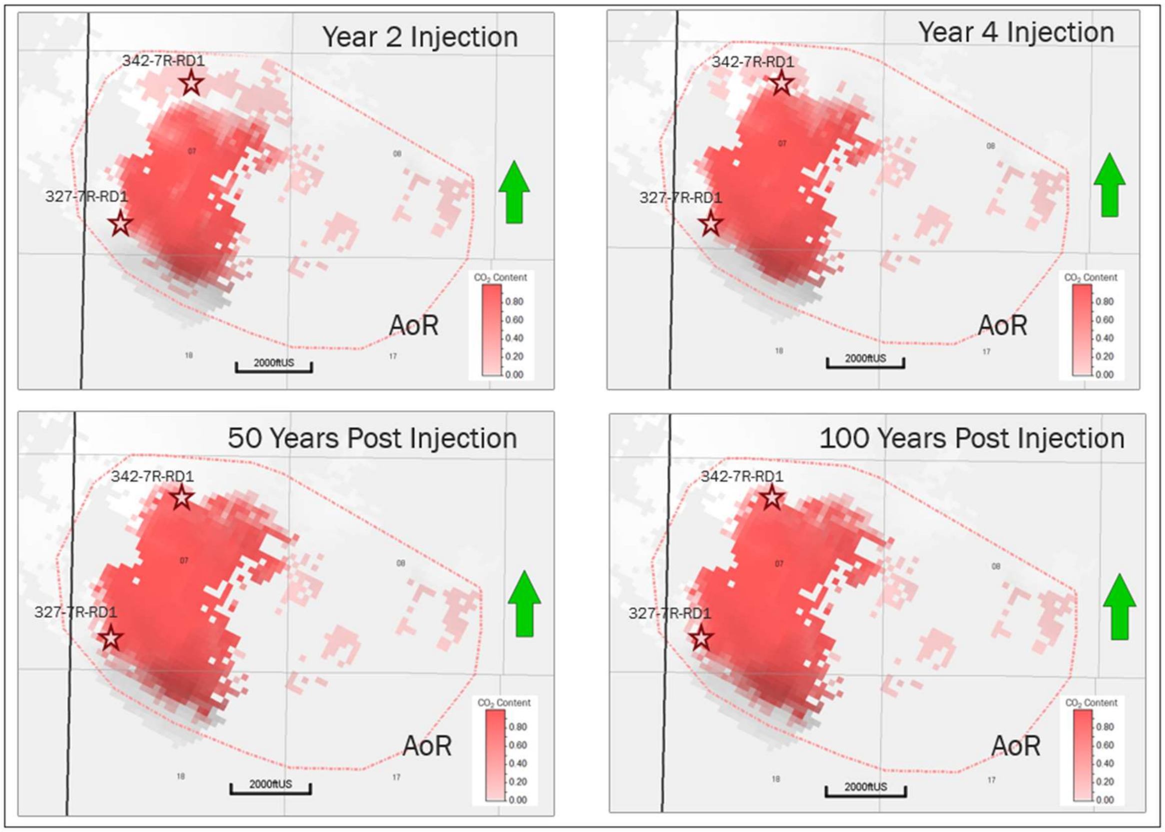
### *Pressure-front monitoring location and frequency*

Table 9 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ.

Quality assurance procedures for these methods are presented in SECTION B – DATA GENERATION AND AQUISTION of the QASP.

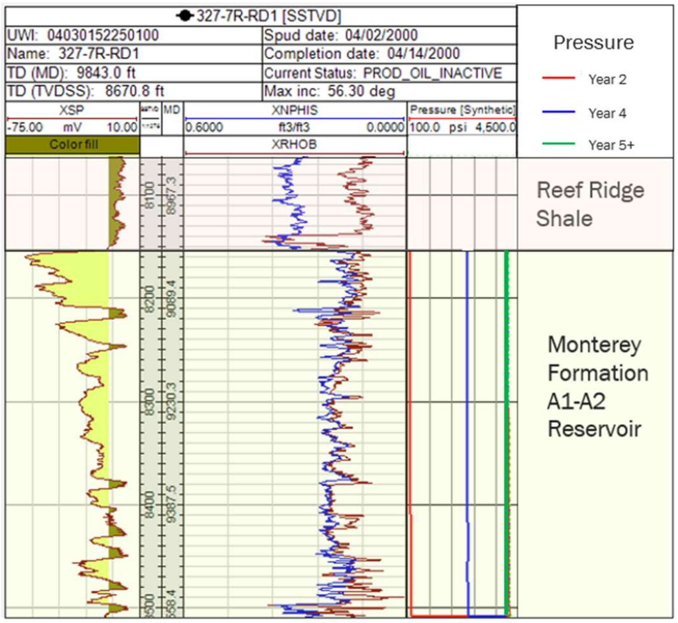
The aerial extent of plume development in the Monterey Formation A1-A2 reservoir will reach the AoR boundaries early in the injection phase. Because the reservoir is pressure depleted, injected $CO_2$ will quickly fill the available pore space. Monitoring well locations with respect to plume development through time are shown in Figure 3.

**Figure 3: Monitoring well location with maps showing plume development through time from computational modeling.**




Monitoring well 327-7R-RD1 pressure development based on computational  is modeled in Figure 4. Note that the reservoir pressure after five years is stable. This is due to the high amount of $CO_2$ that remains super-critical and low quantity of $CO_2$ that will be soluble in either the oil or water phases.

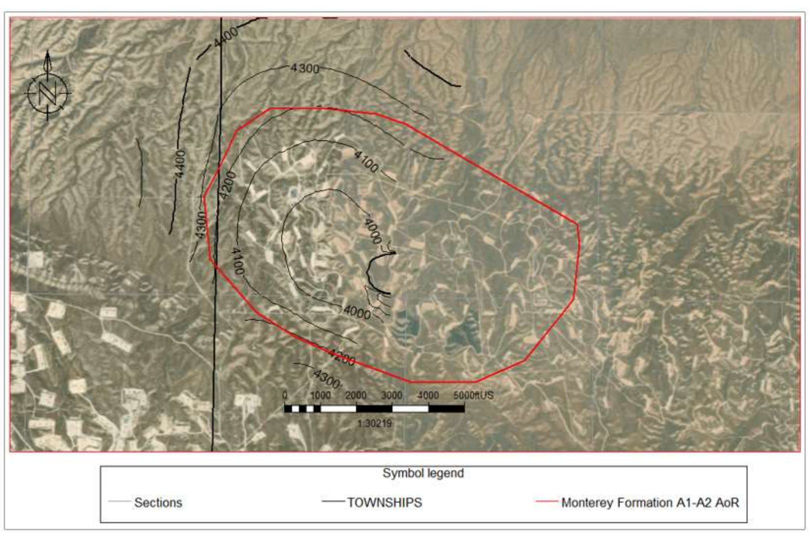
**Figure 4: Monitoring well 327-7R-RD1 showing the pressure increase through time from the computational modeling results.**




### *Pressure-front monitoring details*

Direct pressure monitoring of the plume will be achieved through installation of pressure gauges in monitoring wells 327-7R-RD1 and 342-7R-RD1. The depleted Monterey Formation A1-A2 oil and gas reservoir will be repressurized to the initial/discovery pressure of the reservoir. Figure 5 shows the pressure in the reservoir post injection. CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies.

**Figure 5: Monterey Formation A1-A2 pressure 100 years post injection. This reservoir pressure will be at or below the initial pressure at the time of discovery.**



The modeled pressure increases at monitoring well 327-7R-RD1 are shown in Figure 4. Data acquired though monitoring will be compared to results from computational modeling to ensure suitable definition of the AoR and plume.

**Table 9. Pressure-front monitoring activities.**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Frequency |
|---|---|---|---|
| **DIRECT PRESSURE-FRONT MONITORING** | | | |
| Monterey Formation A1-A2 | Pressure and temperature monitoring | 327-7R-RD1 and 342-7R-RD1 | Continuous |
| **INDIRECT PRESSURE-FRONT MONITORING** | | | |
| All formations | Seismicity | AoR | Continuous |

Induced Seismicity and Fault Monitoring

CTV will monitor seismicity with surface and shallow borehole seismometers in the AoR. The seismometers will be tied in with the regional network to increase resolution and assess natural versus induced seismicity. The seismometers will be able to detect events with a magnitude 0 to 0.5 and will be installed pre-injection to provide baseline seismicity. In addition, CTV will monitor the Southern California Earthquake Data Center (SCEDC) network for seismic events.

## Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan

**ATTACHMMENT D: INJECTION WELL PLUGGING PLAN**
**40 CFR 146.92(b)**

**Elk Hills A1-A2 Storage Project**

## Facility Information

Facility name: Elk Hills A1-A2 Storage
357-7R

Facility contact: Kenneth Haney / CCS Project Manager
28590 Highway 119

Tupman, CA 93276
(661) 763-6101/ Kenneth.Haney@CTV.com

Well location: Elk Hills Oil Field, Kern County, CA
35.32802963 / -119.5449982

Carbon TerraVault 1 LLC (CTV) will conduct injection well plugging and abandonment according to the procedures below.

## Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom-hole pressure gauge. During plugging operations, the heavy-weighted cement slurry, as well as properly weighted displacement fluids, will be over-balanced ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

## Planned External Mechanical Integrity Test(s)

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a).

A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of $CO_2$. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

## Information on Plugs

CTV will use the materials and methods noted in Table 1 to plug the injection well. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Class G cement blend will be utilized that has a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The wells will have this cement placed inside casing from total depth (TD) of the well to surface. The cement will be set in plug segments per CTV's standard procedures.

**Table 1: Plugging details.**

| Plug Information | Plug #1 | Plug #2 | Plug #3 | Plug #4 |
|---|---|---|---|---|
| Diameter of boring in which plug will be placed (in.) | 6.184 | 6.366 | 6.366 | 6.366 |
| Depth to bottom of tubing or drill pipe (ft) | 8,785 | 2,970 | 1,448 | 25 |
| Sacks of cement to be used (each plug) | 65 | 25 | 25 | 5 |
| Slurry volume to be pumped ($ft^3$) | 75 | 28 | 28 | 6 |
| Slurry weight (lb./gal) | 15.6 | 15.6 | 15.6 | 15.6 |
| Calculated top of plug (ft) | 8,427 | 2,845 | 1,323 | 0 |
| Bottom of plug (ft) | 8,785 | 2,970 | 1,448 | 25 |
| Type of cement or other material | Class G | Class G | Class G | Class G |
| Method of emplacement (e.g., balance method, retainer method, or two-plug method) | Running Plug (Coiled Tubing) | Running Plug (Coiled Tubing) | Running Plug (Coiled Tubing) | Running Plug (Coiled Tubing) |

## Narrative Description of Plugging Procedures

### *Notifications, Permits, and Inspections*

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

### *Plugging Procedures*

The following procedures are planned for plugging:

1. Bottom hole pressure from down-hole pressure gauge is recorded and kill fluid density is calculated.

2. Well equipment is removed from the casing and the well is cleaned out to TD during rig operations. Subsequent operations are carried out utilizing a coiled tubing unit (CTU).

3. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up-hole while cementing operations continue. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up-hole while operations are paused to wait on cement. Once the cement has "set", the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval. This process is repeated until cement is placed to surface.

CRC follows the following standards for plugging operations:

- Bottomhole plug - All perforations shall be plugged with cement, and the plug shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shut-off holes, or the oil or gas zone, whichever is highest.
- Base of USDW plug (Underground Source of Drinking Water is defined as a non-exempt aquifer that has >10,000 mg/L DTS):
    - If there is cement behind the casing across the base of USDW, a 100-foot cement plug shall be placed inside the casing across the interface.
    - If the top of the cement behind the casing is below the base of the USDW, squeeze-cementing shall be required through perforations to protect the freshwater deposits. In addition, a 100-foot cement plug shall be placed inside the casing across the fresh-saltwater interface.
- Surface Plug - The casing and all annuli shall be plugged at the surface with at least a 25-foot cement plug.

## ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN 40 CFR 146.93(a)

### Elk Hills A1-A2 Storage Project

**Facility Information**

| | |
|---|---|
| Facility name: | Elk Hills A1-A2 Storage<br>357-7R |
| Facility contact: | Kenneth Haney / CCS Project Manager<br>28590 Highway 119<br><br>Tupman, CA 93276<br>(661) 763-6101/ Kenneth.Haney@crc.com |
| Well location: | Elk Hills Oil Field, Kern County, CA<br>35.32802963 / -119.5449982 |

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault 1 LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

**Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]**

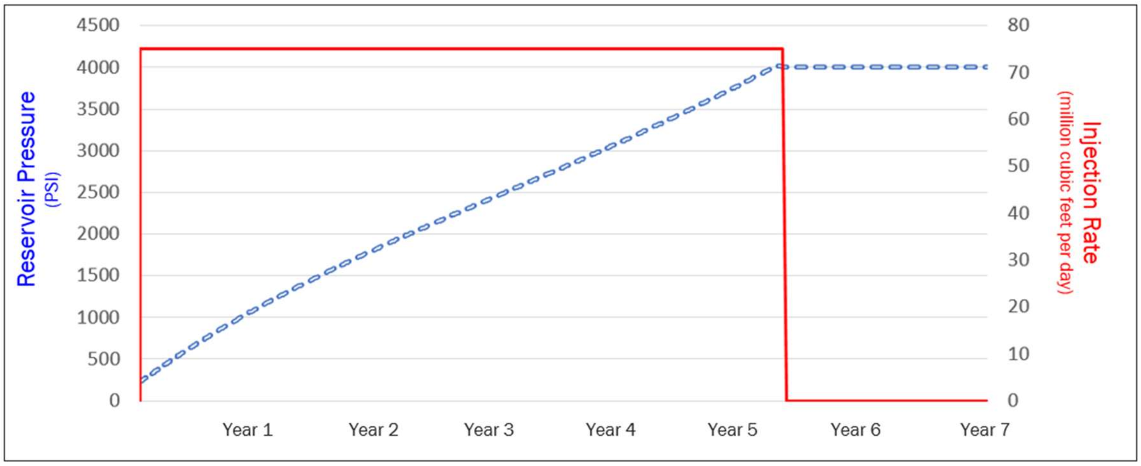
Based on the modeling of the pressure front as part of the AoR delineation, pressure at the injection well is expected to stabilize one year after injection ceases. Final pressure post injection will target the initial reservoir pressure at the time of discovery. Additional information on the projected post-injection pressure declines and differentials is presented in the permit application and the AoR and Corrective Action Plan.

Discussion

The Monterey Formation A1-A2 reservoir will be operated such that the pressure will not exceed the initial pressure at the time of discovery. This operating strategy was developed to minimize the potential for induced seismicity and to ensure confinement of the injectate.

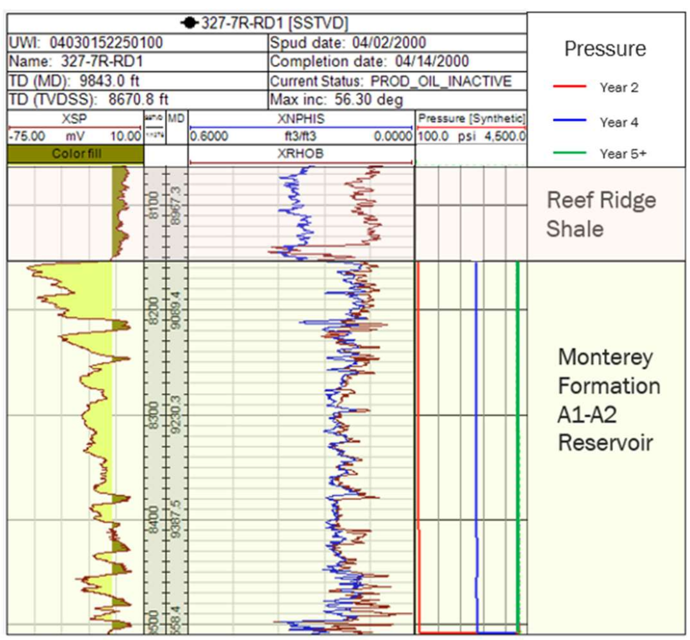
The maximum pressure differential between the injection wellbore and the depleted Monterey Formation A1-A2 storage reservoir exists prior to the commencement of $CO_2$ injection. Through time, the injection pressure differential will shrink, until at the time of project abandonment when the reservoir pressure will be at the initial conditions of the reservoir. Due to high permeability, continuity of the reservoir and low injection pressure differential of the reservoir, pressure stabilization occurs within one year of injection cessation. Figure 1 shows the pressure of the A1-A2 reservoir through time from computational modeling.

**Figure 1: Reservoir pressure and injection rate for the initial seven years of the project. Reservoir pressure stabilizes within the first-year post-injection.**




Pressure at monitoring well 327-7R-RD1 will not decline post-injection (Figure 2). The low water saturation within the Monterey Formation A1-A2 storage reservoir results in greater than 98% of the $CO_2$ injectate remaining super-critical, minimizing the quantity of $CO_2$ dissolving in formation water through time.

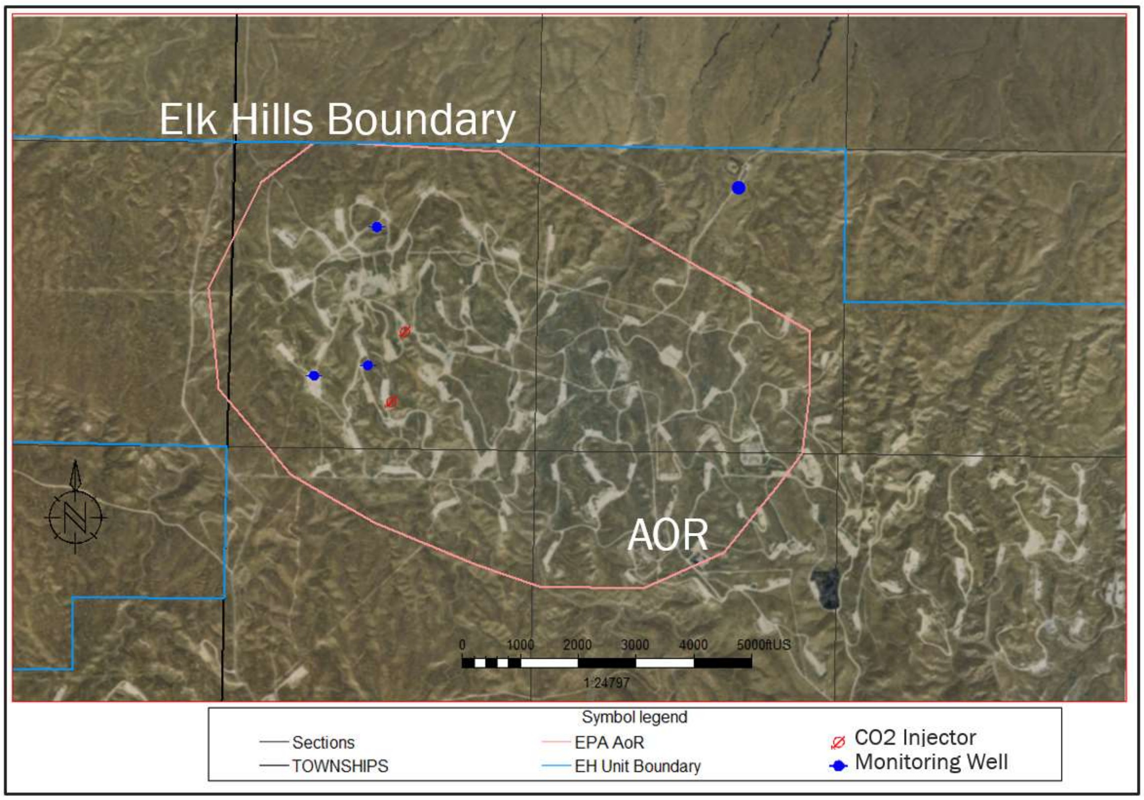
**Figure 2: Pressure at the 327-7R-RD1 monitoring well. Pressure at the end of year five is stable through the end of the computational modeling period (100 years post-injection).**



## Predicted Position of the $CO_2$ Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 3 shows the predicted extent of the plume and pressure front at the end of the PISC timeframe, representing the maximum extent of the plume and pressure front. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84.

**Figure 3: Map of the predicted extent of the CO2 plume at site closure. The pressure of the A1-A2 reservoir will be at or beneath the initial pressure at the time of discovery.**




## Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include a combination of groundwater pressure, fluid composition and storage zone pressure as described in the following sections and will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Post-injection monitoring will include a combination of groundwater monitoring, and storage zone pressure monitoring.

> Pressure monitoring of the Monterey Formation A1-A2 storage reservoir will monitor for pressure stabilization. This is the best method to confirm confinement of the reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.
>
> Throughout most of the AoR there is a very small column of USDW. As such, the down gradient Tulare Formation USDW groundwater monitoring well will continuously assess reservoir pressure. Groundwater samples will be analyzed every five years for indicators of $CO_2$ movement into the USDW.

Surface, mineral and pore space rights for the Monterey Formation A1-A2 reservoir are owned 100% where all activities will take place. As such, site access is guaranteed for the duration of the project and for post-injection monitoring.

### *Monitoring Above the Confining Zone*

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ.

The pressures of these reservoirs may be affected by regional water recharge, injection, or withdrawal. For the Tulare Formation, CTV will compare these results to other groundwater monitoring wells in the Elk Hills Oil Field.

**Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Spatial Coverage | Frequency |
|---|---|---|---|---|
| Tulare Formation | Fluid sampling | 61WS-8R | AoR | Annual |
| | Pressure Monitoring | 61WS-8R | AoR | Continuously |

**Table 2. Summary of analytical and field parameters for ground water samples.**

| Parameters | Analytical Methods |
|---|---|
| **Tulare Formation** | |
| Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se and T1) | ICP-OEC<br>EPA 200.7/6010B |
| Cations (Ca, FE, K, Mg, Na and Si) | ICP-OEC<br>EPA 200.7/6010B |
| Anions (Br, Cl, F, NO3, and SO4) | Ion Chromatography: EPA Method 300 |
| Dissolved CO2 | SM 4500-CO2-C |
| Alkalinity | SM 2510 B |
| pH | EPA 150.1 / SM4500-H+B |
| Total Dissolved Solids (TDS) | SM 4500 C |
| Specific Conductance (field) | SM 2510 B |
| Dissolved Methane | RSK – 175 / Gas Chromatography |
| Temperature (field) | Thermocouple |
| Pressure | Pressure Gauge |

**Table 3. Sampling and recording frequencies for continuous monitoring.**

| Parameter | Device(s) | Location | Min. Sampling Frequency | Min. Recording Frequency |
|---|---|---|---|---|
| During active injection | Pressure Gauge | 61WS-8R | 5 hours | 5 hours |
| Post injection | Pressure Gauge | 61WS-8R | 12 hours | 12 hours |

Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

## *Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]*

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the $CO_2$ plume, including the activities, locations, and frequencies CTV will employ. The parameters to be analyzed as part of fluid sampling in the Monterey Formation A1-A2 (and associated analytical methods) are presented in Table 5.

Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies CTV will employ.

Fluid sampling will be performed as described in B.1. of the QASP; sample handling and custody will be performed as described in B.3. of the QASP; and quality control will be ensured using the methods described in B.5. of the QASP.

**Table 4. Post-injection phase plume monitoring.**

| **Target Formation** | **Monitoring Activity** | **Monitoring Location(s)** | **Frequency** |
|---|---|---|---|
| **DIRECT PLUME MONITORING** | | | |
| Monterey Formation A1-A2 | Fluid Sampling | 327-7R-RD1 and 342-7R-RD1 | Annual |
| **INDIRECT PLUME MONITORING** | | | |
| Monterey Formation A1-A2 | Pulse neutron logging | 327-7R-RD1 and 342-7R-RD1 | Every five years |

**Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.**

| **Parameters** | **Analytical Methods** |
|---|---|
| **Monterey Formation A1-A2** | |
| Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se and T1) | ICP-OEC<br>EPA 200.7/6010B |
| Cations (Ca, FE, K, Mg, Na and Si) | ICP-OEC<br>EPA 200.7/6010B |
| Anions (Br, Cl, F, NO3, and SO4) | Ion Chromatography: EPA Method 300 |
| Dissolved CO2 | SM 4500-CO2-C |
| Alkalinity | SM 2510 B |
| pH | EPA 150.1 / SM4500-H+B |
| Total Dissolved Solids (TDS) | SM 4500 C |
| Specific Conductance (field) | SM 2510 B |
| Dissolved Methane | RSK – 175 / Gas Chromatography |
| Temperature (field) | Thermocouple |
| Pressure | Pressure Gauge |

CTV will employ indirect and direct methods to monitor the pressure front (Table 6). Direct monitoring will include pressure gauges to monitor the pressure of the $CO_2$ plume in the two Monterey Formation A1-A2 monitoring wells. Additionally, seismic monitoring via installed surface and shallow borehole seismometers well will be utilized to detect micro seismic events. Figures 4 and 5 show the location of the monitoring wells and the predicted extent of the $CO_2$ plume in plan view and cross-section.

**Table 6. Post-injection phase pressure-front monitoring.**

| Target Formation | Monitoring Activity | Monitoring Location(s) | Frequency |
|---|---|---|---|
| **DIRECT PRESSURE-FRONT MONITORING** | | | |
| Monterey Formation A1-A2 | Pressure | 327-7R-RD1 and 342-7R-RD1 | Continuous |
| **INDIRECT PRESSURE-FRONT MONITORING** | | | |
| All strata | Seismicity | AoR | Continuous |

**Figure 4: Map showing AoR and well locations for post-injection plume monitoring.**

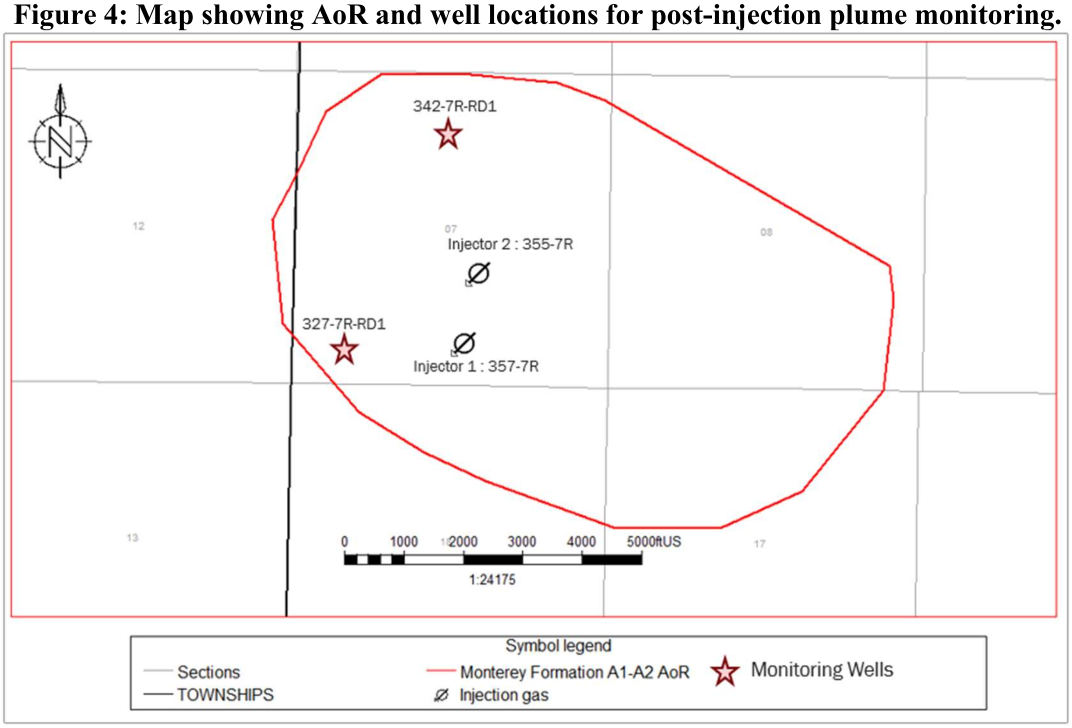
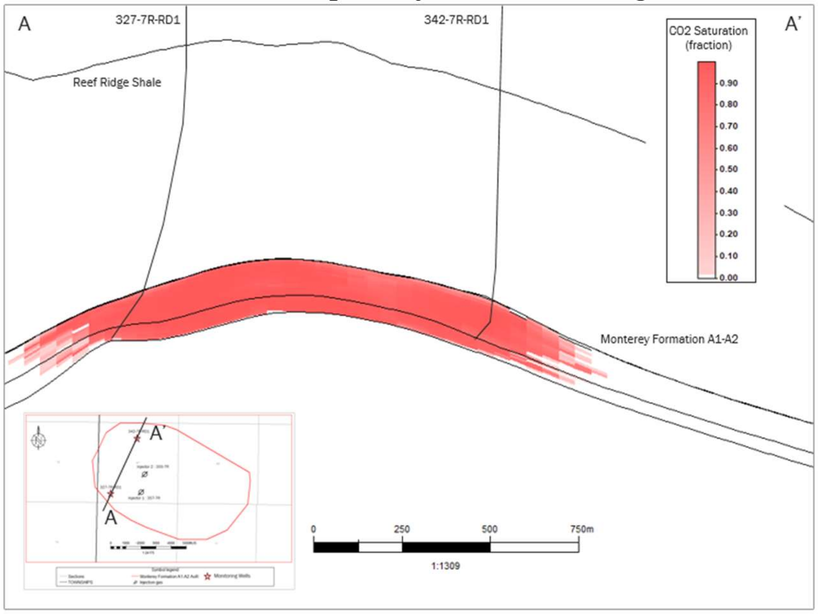


**Figure 5: Cross-section showing plume CO2 injectate plume 100 years post injection and well locations for post-injection monitoring.**




### *Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]*

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period; i.e. well-based monitoring data, sample analysis, and the results from updated site models.

## ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN
## 40 CFR 146.94(a)

### Elk Hills A1-A2 Storage Project

**Facility Information**

| | |
|---|---|
| Facility name: | Elk Hills A1-A2 Storage<br>357-7R |
| Facility contact: | Kenneth Haney / CCS Project Manager<br>28590 Highway 119<br><br>Tupman, CA 93276<br>(661) 763-6101/ Kenneth.Haney@crc.com |
| Well location: | Elk Hills Oil Field, Kern County, CA<br>35.32802963 / -119.5449982 |

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault 1 LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

If CTV obtains evidence that the injected $CO_2$ stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize any release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in Attachment A of the Class VI permit) is appropriate.

**Local Resources and Infrastructure**

Resources in the vicinity of the Elk Hills A1-A2 Storage facility that may be affected as a result of an emergency event at the project site include:

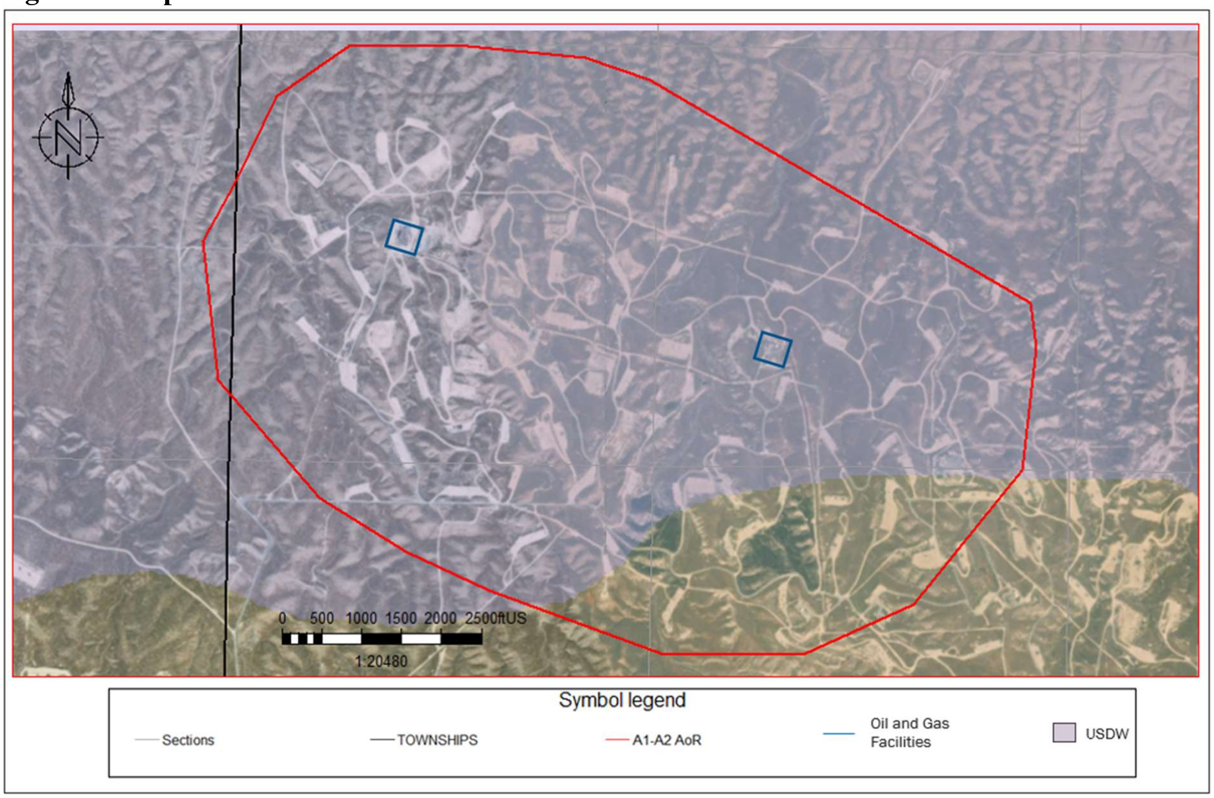
1. Elk Hills oil and gas production resources not associated with the Elk Hills A1-A2 Storage project. These oil and gas operations are operated by California Resources Corporation (CRC) an owner of the Elk Hills A1-A2 Storage project.
2. Upper Tulare USDW overlying the $CO_2$ plume. The USDW is not being utilized in the AoR and CTV does not expect usage in the foreseeable future.

Infrastructure in the vicinity of the Elk Hills A1-A2 Storage facility that that may be affected as a result of an emergency at the project site include:

1. Elk Hills infrastructure owned and operated by CTV that is associated with oil and gas operations.

Resources and infrastructure addressed in this plan are shown in Figure 1.

**Figure 1: Map of the site resources and infrastructure.**




## Potential Risk Scenarios

The following events related to the Elk Hills A1-A2 facility that could potentially result in an emergency response:

- Injection or monitoring (verification) well integrity failure;
- Injection well monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- A natural disaster (e.g., earthquake, tornado, lightning strike);

- Fluid (e.g. brine) leakage to a USDW;
- $CO_2$ leakage to USDW or land surface; or
- Induced seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

**Table 1. Degrees of risk for emergency events.**

| Emergency Condition | Definition |
|---|---|
| Major emergency | Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated. |
| Serious emergency | Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken. |
| Minor emergency | Event poses no immediate risk to human health, resources, or infrastructure. |

## Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

### *Well Integrity Failure*

Integrity loss at the injection well and/or verification well may endanger USDWs. Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
  - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
  - Annulus pressure indicates a loss of external or internal well containment.
  - Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

**Severity:** Low to moderate, dependent on the magnitude of the event.

**Timing of event:** Injection

**Avoidance measures**: Well maintenance, monitoring and control of injection flow and pressure.

**Detection methods:** Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual ($CO_2$ at surface).

**Potential response actions:**

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent $CO_2$ from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Initiate shutdown plan.
    - Shut-in injection well and vent $CO_2$ from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

**Response personnel:** Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

**Equipment:** Drill rig, logging equipment, cement or casing and air and water testing equipment.

***Injection Well Monitoring Equipment Failure***

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

**Severity:** Low

**Timing of event:** Injection

**Avoidance measures**: Well maintenance, and careful monitoring and control of injection flow and pressure.

**Detection methods:** Anomalies in monitoring data, and visual failure of equipment.

**Potential response actions:**

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
  - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
  - Initiate shutdown plan.
  - Shut-in injection well and vent $CO_2$ from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan.
  - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
  - Initiate shutdown plan.
  - Shut-in injection well and vent $CO_2$ from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

**Response Personnel:** Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

**Equipment:** Drill rig, logging equipment, cement or casing and air and water testing equipment.

***<u>Potential Brine or $CO_2$ Leakage to USDW</u>***

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or $CO_2$ leakage into a USDW.

**Severity:** Low

**Timing of event:** Injection

**Avoidance measures**: CTV will operate the project to ensure containment of $CO_2$. Contamination to USDWs will be avoided by:

1. Ensuring injection well integrity through well maintenance and mechanical integrity testing
2. Maintaining the injection pressure below the fracture gradient of the confining Reef Ridge Shale and assessing data from seismic monitoring to ensure competency of the Reef Ridge confining layer.
3. Reviewing monitoring well data to understand plume extent.
4. Monitoring of the Lower Etchegoin dissipation interval that overlies the confining Reef Ridge Shale to establish leakage before migration to USDW.

**Detection methods:** Pressure or water composition change in USDW monitoring well.

**Potential response actions:**

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
    - o Initiate shutdown plan.
    - o Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - o Shut-in injection well and vent $CO_2$ from surface facilities.
    - o If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
        - Remediate unacceptable impacts to the affected USDW.
    - o Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.

- Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or $CO_2$ or "pump and treat" to aerate $CO_2$-laden water).
- Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.

**Response personnel:** Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

**Equipment:** Drill rig, logging equipment, cement or casing and air and water testing equipment.

***Natural Disaster***

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado or lightning strike) may affect surface facilities.

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

**Severity:** Low

**Timing of event:** Injection

**Avoidance measures**: N/A

**Detection methods:** N/A

**Potential response actions:**

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency:
    - Initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in injection well and vent $CO_2$ from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
    - If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

- For a Minor emergency:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity, initiate shutdown plan.
    - Contact security to restrict access to the Elk Hills A1-A2 Storage site.
    - Shut-in injection well and vent $CO_2$ from surface facilities.
    - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

**Response personnel:** Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

***Equipment:*** Drill rig, logging equipment, cement or casing and air and water testing equipment.

***<u>Induced Seismic Event</u>***

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within the AoR, inclusive of a ¼ mile buffer.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the Elk Hills A1-A2 site for seismic activity. In addition to the CTV seismic monitoring, the Southern California Earthquake Data Center has deployed a network to monitor natural seismicity in the area.

**Severity:** Low

**Timing of event:** Injection

An induced seismic event will occur when the reservoir stresses are altered, which would occur during the injection phase.

**Avoidance measures**: N/A

**Detection methods:** The seismic monitoring wells

**Potential response Actions:**

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

**Table 2. Seismic monitoring system, for seismic events > M1.0 with an epicenter within a two-mile radius of the injection well.**

| Operating State | Threshold Condition[1,2] | Response Action[3] |
|---|---|---|
| **Green** | Seismic events less than or equal to M1.5 | 1. Continue normal operation within permitted levels. |
| **Yellow** | Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0 | 1. Continue normal operation within permitted levels.<br>2. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well. |
| **Orange** | Seismic event greater than M1.5 and local observation or felt report | 1. Continue normal operation within permitted levels.<br>2. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well.<br>3. Review seismic and operational data.<br>4. Report findings to the UIC Program Director and issue corrective actions. |
| | Seismic event greater than M2.0 and no felt report | |
| **Magenta** | Seismic event greater than M2.0 and local observation or report | 1. Initiate rate reduction plan.<br>2. Vent $CO_2$ from surface facilities.<br>3. Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well.<br>4. Limit access to wellhead to authorized personnel only.<br>5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary.<br>6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director).<br>7. Determine if leaks to ground water or surface water occurred.<br>8. If USDW contamination is detected:<br>a. Notify the UIC Program Director within 24 hours of the determination.<br>b. Contact environmental and geotechnical professionals for expertise and advice.<br>9. Review seismic and operational data.<br>10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment.<br>11. Report findings to the UIC Program Director and issue corrective actions. |

[1] Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

[2] "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

[3] Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

| Operating State | Threshold Condition[1,2] | Response Action[3] |
|---|---|---|
| **Red** | Seismic event greater than M2.0, and local observation or report, and local report and confirmation of damage[4] | 1. Initiate shutdown plan.<br>2. Vent $CO_2$ from surface facilities.<br>3. Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.<br>4. Limit access to wellhead to authorized personnel only.<br>5. Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary.<br>6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director).<br>7. Determine if leaks to ground water or surface water occurred.<br>8. If USDW contamination is detected:<br>a. Notify the UIC Program Director within 24 hours of the determination.<br>b. Contact environmental and geotechnical professionals for expertise and advice.<br>9. Review seismic and operational data.<br>10. Report findings to the UIC Program Director and issue corrective actions. |
| | Seismic event >M3.5 | |

**Response personnel:** Emergency response personnel, California Geological Survey, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

**Equipment:** Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

## Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Ken Haney (661- 763-6101)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director

Bill Blair (562-743-8336)

[4] Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

**Table 3. Contact information for key local, state, and other authorities.**

| Agency | Phone Number |
|---|---|
| Local police | 9-1-1 (Emergency)<br>661-861-3110 (Non-emergency) |
| California Governor's Office of Emergency Services (Cal OES) | (916) 845-8506 |
| UIC Program Director (CalGEM) | 661-322-4031 |
| EPA National Response Center (24 hours) | 800-424-8802 |
| California Geological Survey | (916) 322-1080 |
| Kern County Fire Department | 9-1-1 (Emergency)<br>661-324-6551 (Non-emergency) |
| California Air Resources Board (CARB) | 800-242-4450 |

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

## Emergency Communications Plan

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, $CO_2$ source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

**Plan Review**

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within three months following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

**Staff Training and Exercise Procedures**

All CTV staff and contractors operating at the $CO_2$ sequestration facilites, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

$CO_2$ Facilities Training

Onsite and classroom training for facility and infrastructure security, maintainence, and operations.

$CO_2$ Safety Training

**Carbon dioxide detection equipment:** Operation and maintainence of personal monitors, portable multi-gas monitors and stationary montiors throughout thefacility.

**Carbon Dioxide Haxards:** Accidental exposure, adverse health effects, workplace exposure limits and first aid.

**Emergency Response:** Training in the event of CO2 leakage and exercies and drills simulating potential emergency situations.

## Class VI UIC Project Plan Submissions

This submission is for:

Project ID: R09-CA-0003

Project Name: CRC CalCapture A1-A2

Current Project Phase: Pre-Injection Prior to Construction

## Testing and Monitoring

Are You Making a Testing and Monitoring Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Testing and Monitoring Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/ProjPlan-08-02-2021-1951/Attachment--C--Testing--and--Monitoring--Plan.pdf

Appendices and Supporting Materials Upload

Attach Any Supporting Documentation for the Testing and Monitoring Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/ProjPlan-08-02-2021-1951/Attachment--QASP.zip

## Injection Well Plugging

Are You Making an Injection Well Plugging Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Injection Well Plugging Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/ProjPlan-08-02-2021-1951/Attachment--D--Injection--Well--Plugging--Plan.pdf

Appendices and Supporting Materials Upload

## PISC and Site Closure

Are You Making a Post-Injection Site Care and Site Closure Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Post-Injection Site Care and Site Closure Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/ProjPlan-08-02-2021-1951/Attachment--E--Post--Injection--Site--Care--and--Closure.pdf

Appendices and Supporting Materials Upload

## Emergency and Remedial Response

Are You Making an Emergency and Remedial Response Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Emergency and Remedial Response Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/ProjPlan-08-02-2021-1951/Attachment--F--Emergency--and--Remedial--Response--Plan.pdf

Appendices and Supporting Materials Upload

## Complete Submission

Authorized submission made by: Travis Hurst

For confirmation a read-only copy of your submission will be emailed to: travis.hurst@crc.com

| Top MD (ft | Btm MD (f | Nominal OD (in) |
|---|---|---|
| 20 | 8990 | 7 |

## CLASS VI AOR BOUNDARY CONDITIONS DESCRIPTION

## INJECTION WELL 357-7R
## ELK HILLS A1-A2 PROJECT

### AoR Boundary Conditions

Elk Hills A1-A2 Site Geology and Hydrology

The Northwest Stevens Field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation A1-A2, present in the northwestern portion of the field, pinch out towards the southeast (Figure 1, cross-section A-A') and compares to the crest, the reservoir quality is lower on edges of the structure (Figure2).

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation A1-A2, but for all Monterey accumulations in the greater Elk Hills area.

**Figure 1: Cross-section A-A' showing the Monterey Formation A1-A2 sands. Note the increasing shale content on the edges of the structure.**

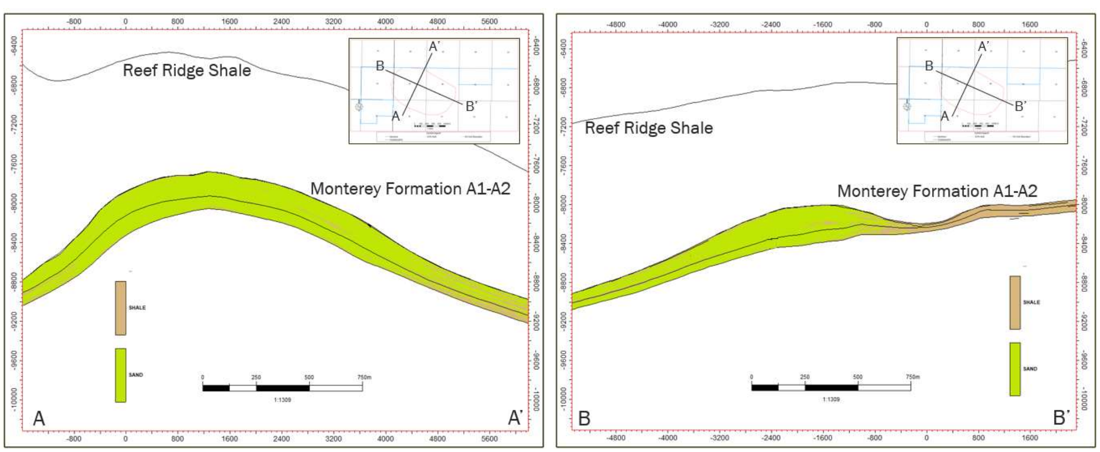
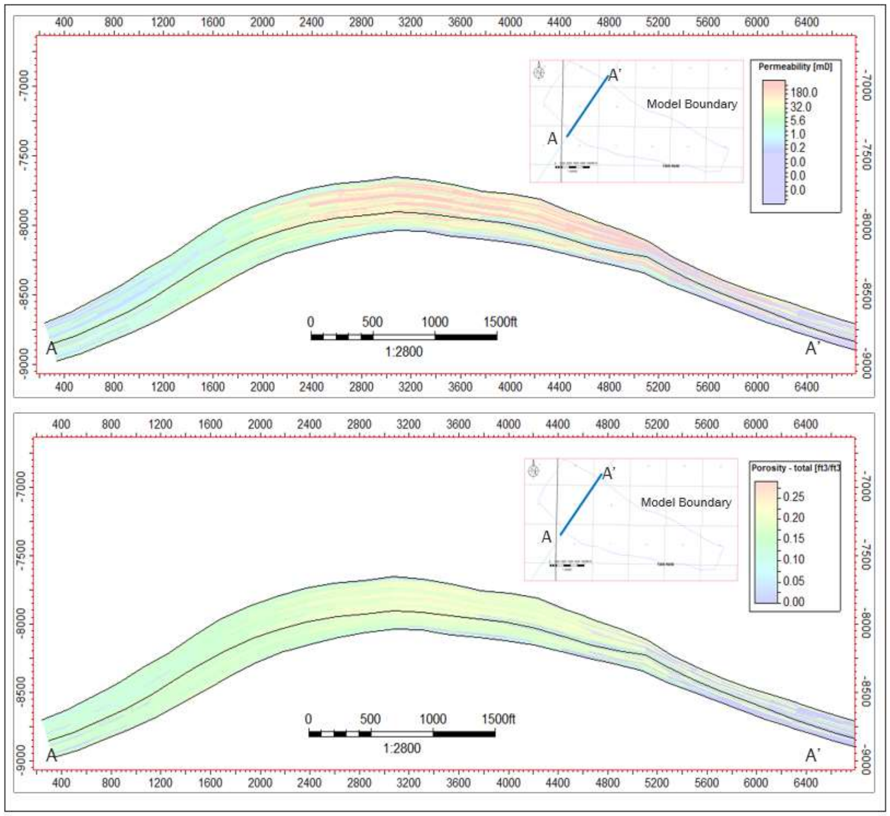


**Figure 2: Reservoir quality of the Monterey A1-A2 reservoir. Note the reduction in porosity and permeability of the edges of the anticline structure.**




Reservoir Development

The CalCapture Class VI injection wells will target injection in the Monterey Formation A1-A2 sands. The Monterey Formation A1-A2 oil and gas reservoir was discovered in the 1970's and has been developed with primary production and pressure maintenance (Table 1). Gas and water injection initiated in 1982 supported reservoir pressures and helped maintain oil production. Starting in the year 2000, pressure maintenance ceased, and the gas cap reservoir was "blown-down", depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 200-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

**Table 1: Production and injection volumes for the Monterey Formation A1-A2 reservoir.**

| Process | Phase | Volume |
|---|---|---|
| Production | Oil | 28 million barrels |
| | Gas | 193 billion cubic feet |
| | Water | 9 million barrels |
| Injection | Water | 6 million barrels |
| | Gas | 175 billion cubic feet |

Boundary Conditions

No-flow boundary conditions were applied to the Monterey Formation A1-A2 reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

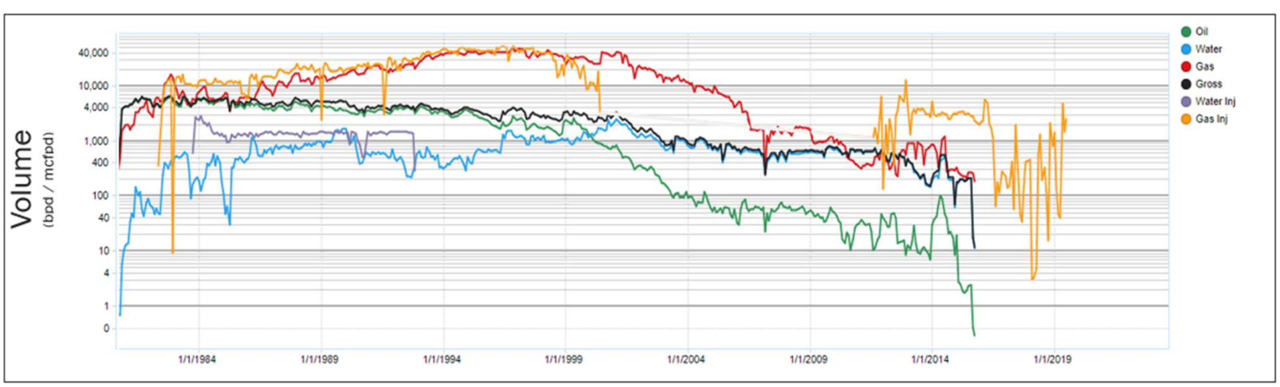
2. Performance data from operating the Monterey Formation A1-A2 oil and gas reservoir indicates  no connection to an active aquifer.

    i. Historical production data (Figure 3) shows minimal water production, supporting limited aquifer influx.

    ii. Gas injection and subsequent gas blow-down (Figure 3) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

    iii. Pressure in the reservoir is 200 - 300 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

**Figure 3: Monterey Formation A1-A2 production and injection data.**



## Class VI UIC Area of Review and Corrective Action

This submission is for:

Project ID: R09-CA-0003

Project Name: CRC CalCapture A1-A2

Current Project Phase: Pre-Injection Prior to Construction

## Overview

Simulator Used for AoR delineation modeling: GEM

Simulator Description/Documentation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/CMG_GEM_Product_Brochure_2019.pdf

Description of File Contents: File describes Computer Modeling Group's (CMG) compositional simulation software (GEM) used for computational modeling.

Total Simulation Time From Start of Injection: 110 yrs

Additional AoR Delineation Information: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/AoR--State.pdf

## Model Domain

Coordinate System: UTM

Horizontal Datum: NAD83

Coordinate System Units: ft

Vertical Datum: Mean Sea Level

Describe Vertical Datum: Sea level

Zone: 5

Mesh Type: Unstructured

Domain Size in Global Units Specified Above

Domain Coordinates File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Resqml--Metadata.pdf

Grid Size

Number of Nodes in x: 188 y: 69 z: 97

Grid Spacing: Variable

Grid File Format: ASCII file containing vertices and elements

Grid File Description: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Grid--Description.pdf

Grid Data File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Grid--file--size--too--large--to--be--uploaded.pdf

Faults Modeled: No

Caprock Modeled: No

Image File(s) for Model Domain Grid: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Computational--Modeling--Grid.jpg

## Processes Modeled by Simulator

Reservoir Conditions:

Supercritical CO2 Conditions

Phases Modeled:

Aqueous Supercritical CO2

Aqueous Phase:

Phase Compressibility: Incompressible

Phase Composition: Compositional

Aqueous Phase Components:

CO2 Water Oil Methane Describe Oil: Initally an oil and gas reservoir.

Supercritical CO2 Phase:

Phase Compressibility: Compressible

Phase Composition: Compositional

Supercritical CO2 Phase Components:

CO2 Water Oil Describe Oil: Initally an oil and gas reservoir.

Equation of State Description Including Reference: CMG software GEM.

File with EOS Reference or Documentation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/SPE-89343_Reservoir--Simulation--of--CO2--Storage--in--Deep--Saline--Aquifers.pdf

Multifluid Flow Processes:

Thermal Conditions: Isothermal

Heat Transport Processes:

Geochemistry Modeled: No

Geomechanical/Structural Deformations Modeled: Yes

File Describing Geomechanical/Structural Modeling: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Geomechanical--Modeling.pdf

## Rock Properties and Constitutive Relationships

Porosity/Permeability Model

Single Porosity

Porosity Distribution: Heterogeneous

Spatially Variable Porosity File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Porosity--Layer--74.crsmeta.zip

File Describing how Porosity was Determined and Assigned to Numerical Model: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Porosity--Determination.pdf

Image Files for Porosity Distributions: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Porosity.pdf

Permeability Distribution: Heterogeneous

Spatially Variable Permeability File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Permeability--Layer--74.crsmeta.zip mD

File Describing how Permeability was Determined and Assigned to Numerical Model:

https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Permeability--Determination.pdf

Image Files for Permeability Distributions: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Permeability.pdf

Number of Rock Types Modeled: 1

Description of Rock Type Selection and Assignment: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Facies.pdf

Rock Type Distribution Data File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Sand--Facies--Layer--74.crsmeta.zip

Image Files for Rock Type Distribution: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Facies--2.pdf

### Rock Type #1

Rock Compressibility: Bulk

Rock Compressibility Distribution: Single Value

Compressibility Value: 3.5 1/Pa

Constitutive Relationships

Aqueous Saturation vs. Capillary Pressure: Functional Form

File Describing Functional Form Used for Aqueous Saturation vs Capillary Pressure:

https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Saturation--Function.pdf

Aqueous Trapped Gas Modeled: Yes

Hysteresis other than non-wetting fluid trapping: No

Aqueous Relative Permeability: Functional Form

File Describing Functional Form Used for Aqueous Relative Permeability:

https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Relative--Permeability.pdf

Hysteresis other than non-wetting fluid trapping: No

Gas Relative Permeability: Functional Form

File Describing Functional Form Used for Gas Relative Permeability: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Relative--Permeability--2.pdf

Hysteresis other than non-wetting fluid trapping: No

Porosity and Permeability Reduction Due to Salt Precipitation

## Boundary Conditions

Attach Boundary Conditions Description File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/AoR--Boundary--Conditions.pdf

## Initial Conditions

Initial Phases in Domain: Gas

Initial Gas Pressure: Varying with Depth, Temperature, and Salinity

Initial Gas Pressure: 230 psi at Reference Elevation: -8300 ft

Initial Temperature: Spatially Constant

Initial Temperature: 240 F

Initial Dissolved Water in CO2: None

## Operational Information

Number of Injection Wells: 2

### Injection Well #1

Well Direction: Directional

Well Trajectory File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/357-7R--Deviation.crsmeta.zip

Wellbore Diameter: Variable

Wellbore Diameter File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/357-7R--Casing.xlsx

Well Screen Interval Provided as: Multiple Intervals

Screened Interval File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/357-7R--Perforations.csv

Mass Rate of Injection: 0.37 MMT/yr

Total Mass of Injection: 4 MMT

Fracture Gradient: 0.97 psi/ft

Maximum Injection Pressure: 7407 psi Elevation Corresponding to Pressure: 8485 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Fracture--Gradient--and--Maximum--Operating--Pressure.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period

Injection Start Date: 01/01/2024 Stop Date: 01/01/2039

### Injection Well #2

Well Direction: Directional

Well Trajectory File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/355-7R--Deviation.crsmeta.zip

Wellbore Diameter: Variable

Wellbore Diameter File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/355-7R--Casing.csv

Well Screen Interval Provided as: Multiple Intervals

Screened Interval File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/355-7R--Perforations.csv

Mass Rate of Injection: 0.37 MMT/yr

Total Mass of Injection: 4 MMT

Fracture Gradient: 0.97 psi/ft

Maximum Injection Pressure: 7387 Pa Elevation Corresponding to Pressure: 8462 m

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File:

https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Fracture--Gradient--and--Maximum--Operating--Pressure--2.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period

Injection Start Date: 01/01/2024 Stop Date: 01/01/2039

Number of Production/Withdrawal Wells: 0

## Model Output/Results

Provide file name and corresponding spatial location for each file: Pressure and CO2 saturation time series for monitoring well pressure and CO2 saturation

Time-Series File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Monitoring--Well--327-7R.zip

Provide file name and corresponding variable and time stamp for each file: Maps and grids showing plume development.

Snapshot File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Time--Series--Grids.zip

Provide file name and corresponding description of surface for each file: There are no internal nor external boundaries within the AoR.

Surface Flux File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Flux.pdf

## AoR Pressure Front Delineation

Lowermost USDW:

Name of Lowermost USDW: Upper Tulare

Water Density: 1.003 gm/cm^3 at Elevation: 1628 ft

Location of Measurement for Density: 43WS-13B

Temperature: 87.6 F at Elevation: 1628 m

Location of Measurement: 43WS-13B

Pressure: 14.6 psi at Elevation: 704 ft

Location of Measurement: 362-7R

Salinity: 4962 mg/L at Elevation: 704 ft

Location of Measurement: 362-7R

Elevation of bottom of USDW: 848 ft

Injection Zone:

Name of Injection Zone: Monterey Formation A1-A2

Water Density: 1.0143 gm/cm^3 at Elevation: 8590.6 ft

Location of Measurement: 381-17R

Temperature: 250 C at Elevation: 8590.6 ft

Location of Measurement: 381-17R

Pressure: 100 psi at Elevation: 8590.6 m

Location of Measurement: 381-17R

Salinity: 24877 mg/L at Elevation: 8590.6 m

Location of Measurement: 381-17R

Elevation of top of Injection Zone: 8590.6 m

Method of Estimating Critical Pressure: Static Mass Balance

Assumptions: Uniform denisty

File Describing Critical Pressure Estimation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Critical--Pressure--Calculation.pdf

Estimated Critical Pressure: 3400 psi

Delineated AoR:

Shapefile or KML File Showing Delineated AoR: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/AoR.shx

https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/AoR.prj https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/AoR.shp

https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/AoR.dbf

## Corrective Action

File with Location of All Penetrations within AoR: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/AoR--Well--List.csv

Supporting Documentation: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/File--size--too--large.docx

## Area of Review and Corrective Action Plan [40 CFR 146.82(a)(13) and 146.84(b) or applicable state requirements]

Are you making an Area of Review and Corrective Action Plan submission at this time?: Yes

Reason for Project Plan Submission: Permit application submission

Project Plan Upload

Attach the Area of Review and Corrective Action Plan: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/AoRModeling-08-02-2021-1947/Attachment--B--Area--of--Review--and--Corrective--Action--Plan.pdf

Appendices and Supporting Materials Upload

## Area of Review Reevaluation [40 CFR 146.84(e) or applicable state requirements]

Minimum fixed frequency of AoR reevaluation: 5 Years

Are you making an Area of Review reevaluation submission at this time?: No

Reevaluation Background

Reevaluation Materials

Please upload your amended AoR and Corrective Action Plan on the previous tab.

## Complete Submission

Authorized submission made by: Travis Hurst

For confirmation a read-only copy of your submission will be emailed to: travis.hurst@crc.com

No addition information required by state.

Please contact Travis Hurst at 661-342-2409 or travis.hurst@crc.com

**ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN**
**40 CFR 146.84(b)**

## Facility Information

| | |
|---|---|
| Facility name: | Elk Hills A1-A2 Storage<br>357-7R |
| Facility contact: | Kenneth Haney / CCS Project Manager<br>28590 Highway 119<br>Tupman, CA 93276<br>(661) 763-6101/ Kenneth.Haney@crc.com |
| Well location: | Elk Hills Oil Field, Kern County, CA<br>35.32802963 / -119.5449982 |

## Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of the subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies by subzone, as well as observed fluid contacts and saturations for each fluid phase. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. Carbon TerraVault 1 LLC (CTV) licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for each hydrocarbon and water phase
- Liquid and gas relative permeability
- Capillary pressure data
- Well completion, production, and injection data from the reservoir's entire depletion history

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case for the CalCapture A1-A2 project, the AoR encompasses the maximum aerial extent of the $CO_2$ plume (e.g., supercritical, liquid, or gaseous). Reservoir pressure will be at or beneath the initial/discovery pressure, minimizing the already minor potential for induced seismicity and ensure no elevated pressure post injection.

***Model Background***

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous), multi-phase fluids, predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the $CO_2$ plume utilized the Peng-Robinson Equation of State (Reference 1) and the solubility of $CO_2$ in water is modeled by Henry's Law (Reference 2, 3). The Peng-Robinson Equation of State establishes the interaction/solubility of $CO_2$ and residual oil in the reservoir. Solubility of $CO_2$ in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of $CO_2$ stored and simulates lateral and vertical movement of the $CO_2$ to define the AoR.

The simulator predicts the evolution of the $CO_2$ plume by:

1. Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.

2. Forecasting the $CO_2$ plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).

3. Assessing the movement of $CO_2$ after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous $CO_2$ sequestration peer reviewed papers, including:

1. Simulation of $CO_2$ EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al

2. Model Predictions Via History Matching of $CO_2$ Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al

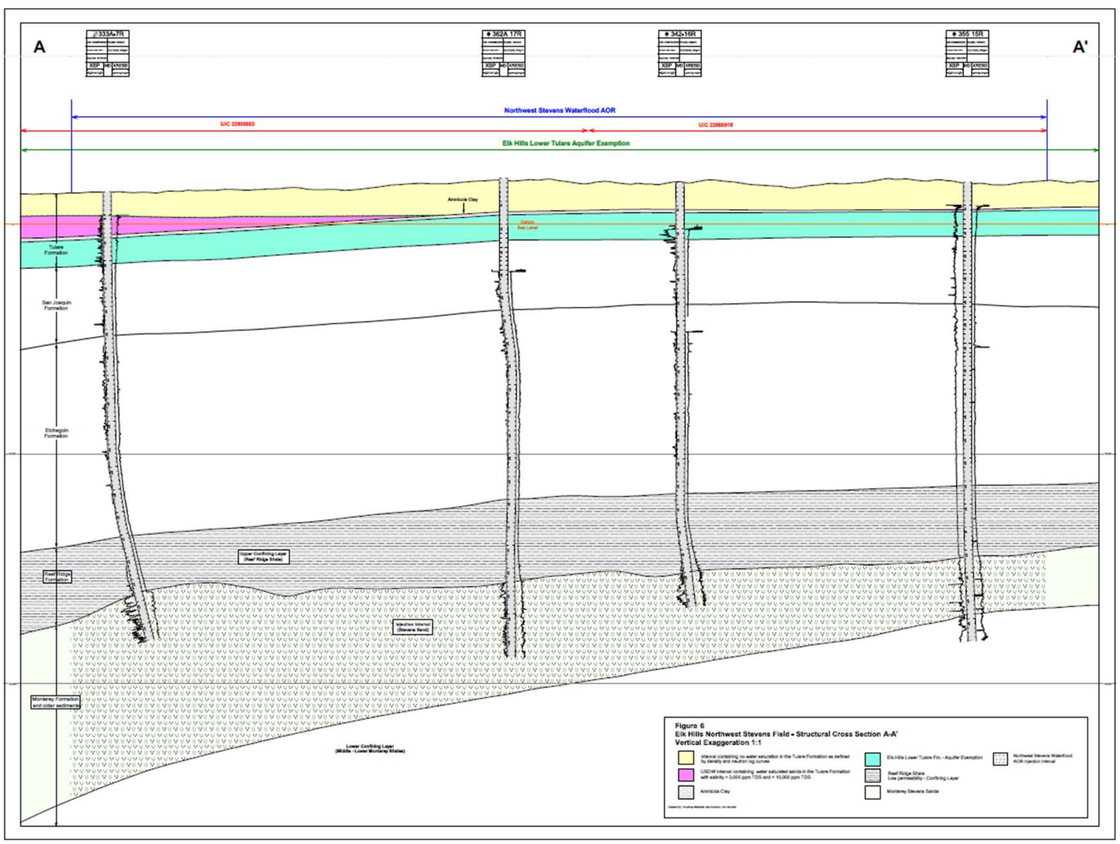
3. Geomechanical Risk Mitigation for $CO_2$ Sequestration in Saline Aquifers. Tran, Davis et al.

### *Site Geology and Hydrology*

The Northwest Stevens Field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation A1-A2, present in the northwestern portion of the field, pinch out towards the southeast (Figure 1, cross-section A-A'), while the lowermost sands, are present across the entire structure.

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation A1-A2, but for all Monterey accumulations in the greater Elk Hills area.

**Figure 1: Cross-section A-A' showing the Monterey Formation A1-A2 sands pinching-out on the NWS anticline.**



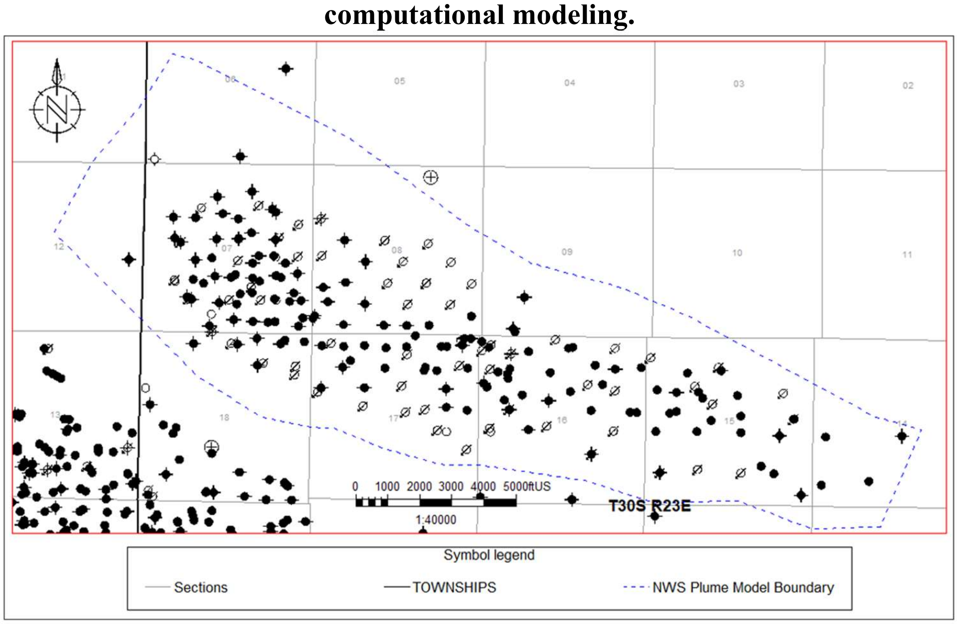

The CalCapture Class VI injection wells will target injection in the Monterey Formation A1-A2 sands. The Monterey Formation A1-A2 oil and gas reservoir was discovered in the 1970's and has been developed with primary production and pressure maintenance (Table 1: Production and Injection volumes). Gas and water injection initiated in 1982 supported reservoir pressures and helped maintain oil production. Starting in the year 2000, pressure maintenance ceased, and the gas cap reservoir was “blown-down”, depleting the reservoir pressure. Since blow-down, reservoir pressure has remained at 200-300 PSI, indicating a closed reservoir with minimal water influx and/or connection to an aquifer.

**Table 1: Production and injection volumes for the Monterey Formation A1-A2 reservoir.**

| Process | Phase | Volume |
|---|---|---|
| Production | Oil | 28 million barrels |
| | Gas | 193 billion cubic feet |
| | Water | 9 million barrels |
| Injection | Water | 6 million barrels |
| | Gas | 175 billion cubic feet |

Well data, open-hole well logs and core (Figure 2), define the subsurface geological characteristics of stratigraphy, lithology and rock properties. Reservoir performance information (production and injection rates and volumes, reservoir and wellbore pressures) complements the static characterization by adding the dynamic components, such as reservoir continuity and hydrogeology.

**Figure 2: Location of wells with open-hole log data used to develop the static model used in computational modeling.**




.

Model Domain

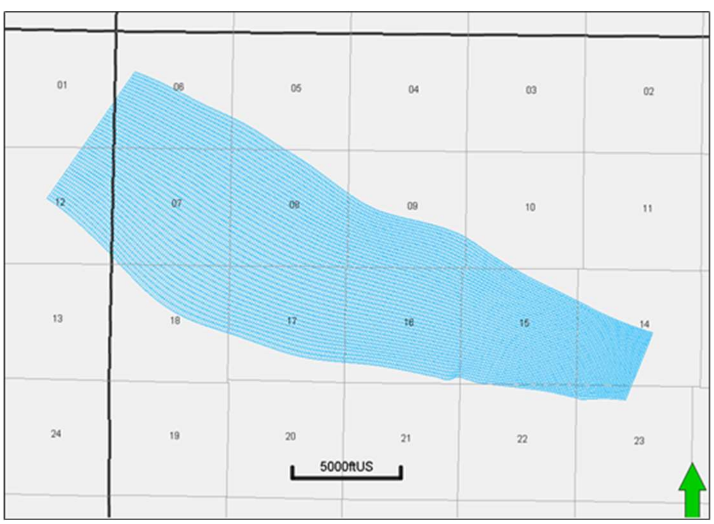
A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 2.

**Table 2. Model domain information.**

| | | | |
|---|---|---|---|
| **Coordinate System** | State Plane | | |
| **Horizontal Datum** | NAD 83 | | |
| **Coordinate System Units** | Feet | | |
| **Zone** | CA83-VF | | |
| **FIPSZONE** | 0405 | **ADSZONE** | 3376 |
| **Coordinate of X min** | 6,095,241.81 | **Coordinate of X max** | 6,122,433.26 |
| **Coordinate of Y min** | 2,302,015.15 | **Coordinate of Y max** | 2,316,903.12 |
| **Elevation of bottom of domain** | -10,426.35 | **Elevation of bottom of domain** | -6,670.36 |

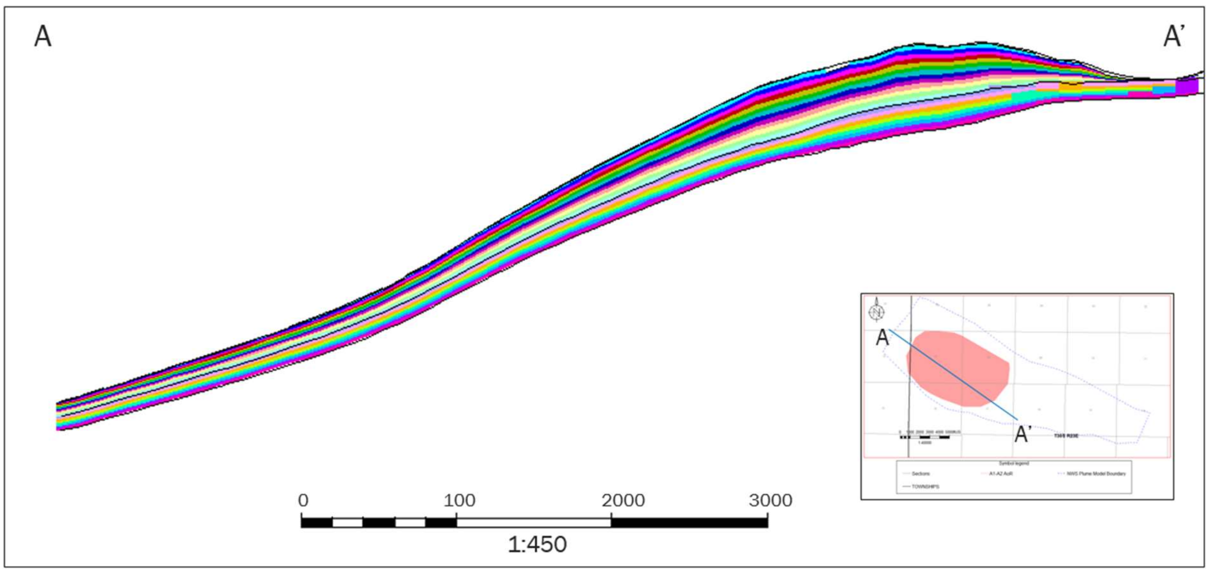
The geo-cellular grid is uniformly spaced throughout the 6.4 square mile model area (Figure 3) at 150 feet x 150 feet. The model is oriented at 55 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and the peripheral area of elevated pressure.

**Figure 3: Plan view of the model boundary showing the extent of the CO2 plume that defines the AoR.**



The reservoir has been separated into two zones, A1 and A2 sands, with 8 and 13 layers (Figure 4) respectively and an average grid cell height of 11.5 feet. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing $CO_2$ movement. Well data that defines the stratigraphy also defines the structure of the A1-A2 storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

**Figure 4: Static model layering of the Monterey Formation A1-A2 reservoir. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale.**




### *Porosity and Permeability*

Figure 3 shows the AoR and the well penetrations that have open hole triple combo logs and core data used for the model parameters. Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Mercury Injection Capillary Pressure (MICP) permeability data from core analysis constrains the permeability function (Figure 5) that is dependent on porosity and clay volume.

**Figure 5: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.**

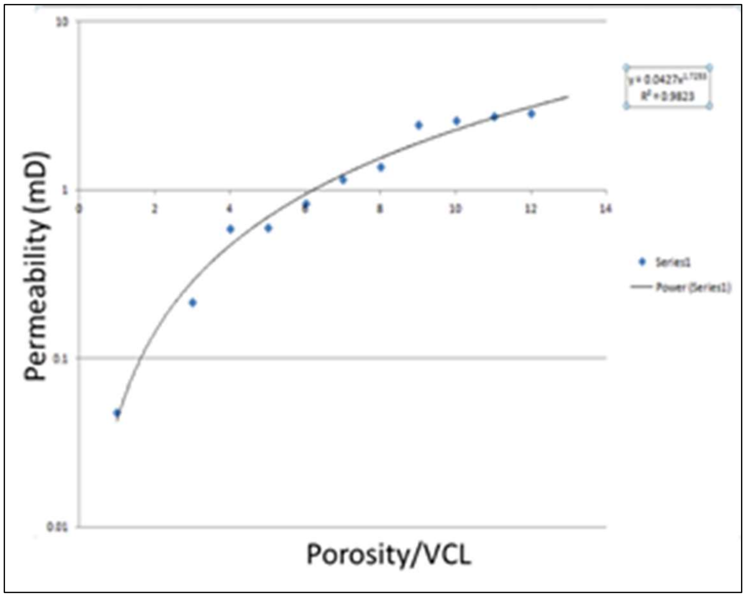



**Figure 6: Monterey Formation A1-A2 sands porosity and permeability distribution in the static model.**

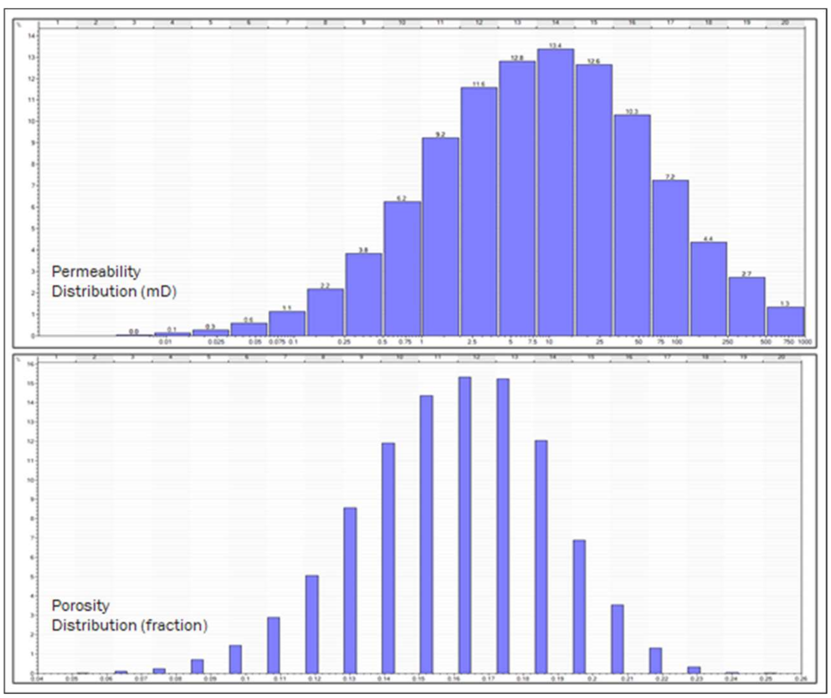
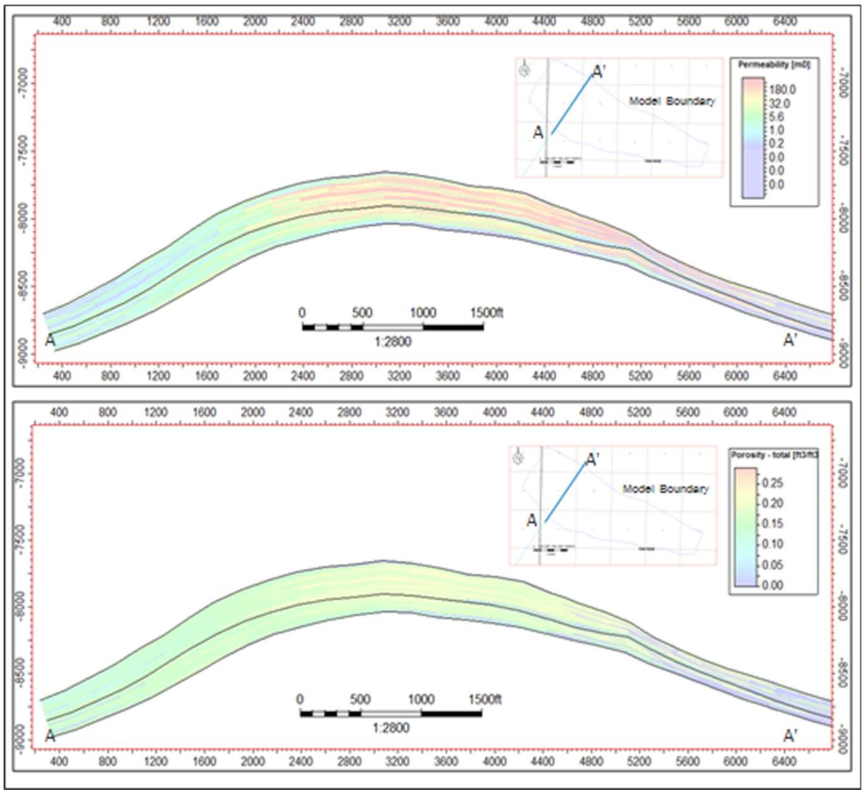



Figure 6 shows porosity and permeability histograms for the Monterey Formation A1-A2 sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 7 shows the permeability and porosity distribution in cross-section A-A'.

Reservoir quality is the highest at the top of the anticline, porosity and permeability are lower on the edges.

**Figure 7: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.**



### *Constitutive Relationships and Other Rock Properties*

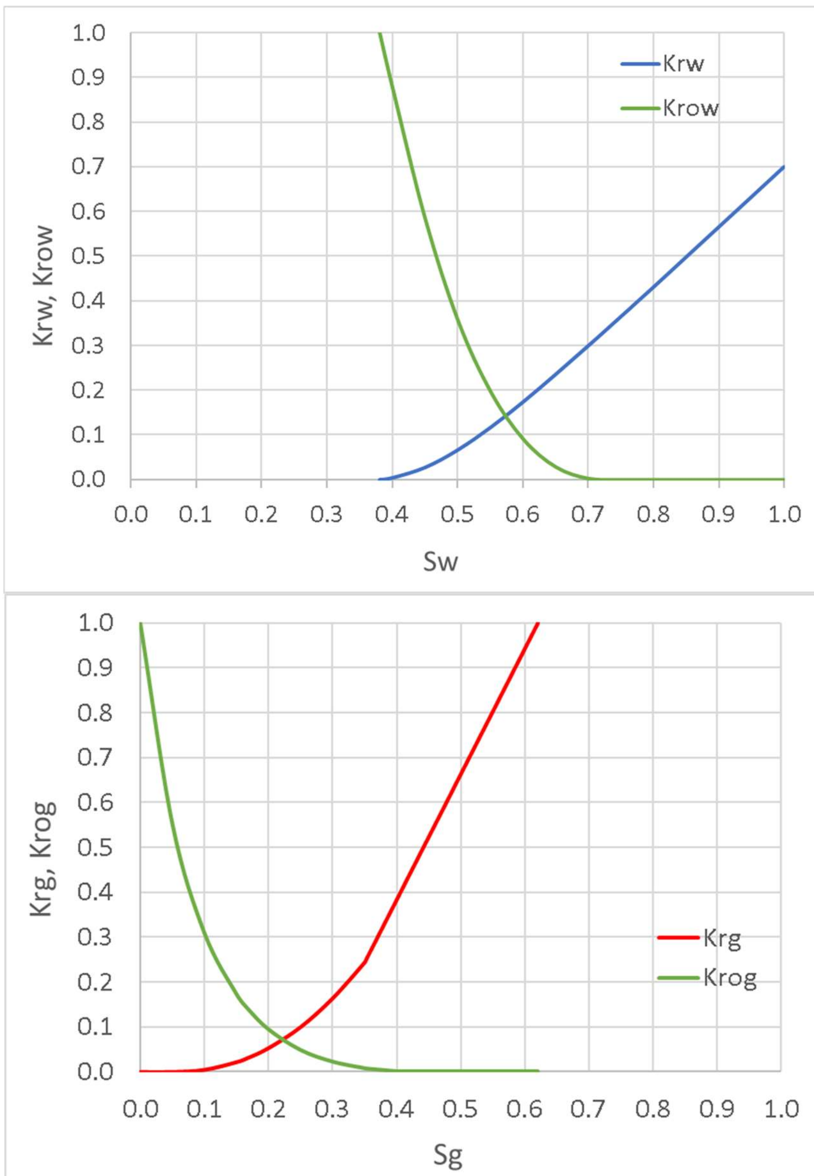
The Monterey Formation A1-A2 reservoir gas cap overlies an oil band, followed by a basal water zone. Contacts for gas, oil, and water depths are derived from open-hole well logs and production analysis and verified through simulation and history matching. Single values for the saturation have been assumed for the computational model study. Table 3 shows the reservoir contacts and saturations used in the computational model.

**Table 3: Gas, oil and water contacts used in the computational modeling study. Values derived by open hole well logs and production analysis.**

| | Gas Cap | Oil Band | Water Zone |
|---|---|---|---|
| Contact (depth sub-sea) | Gas - Oil<br>8,400 | Oil - Water<br>8,550 | |
| Saturation (fraction) | Water: 0.18<br>Gas: 0.82 | Oil: 0.15<br>Water: 0.85 | Water: 1.0 |

With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving Krw, Krow, Krg, and Krog as a function of water or liquid saturation. Data acquired from core flood and/or capillary pressure testing determines these relationships. Figure 8 shows the relative permeability curves used in the computational modeling.

**Figure 8: Relative permeability curves for Krg-Krog and Krw-Krow used in the computational model study.**



### *Boundary Conditions*

No-flow boundary conditions were applied to the Monterey Formation A1-A2 reservoir in the computational modeling. These conditions were based on the following:

1. The overlying Reef Ridge Shale is continuous through the area, has a low permeability (less than 0.01 mD) and has confined oil and gas operations, that include the injection of water and gas, since discovery.

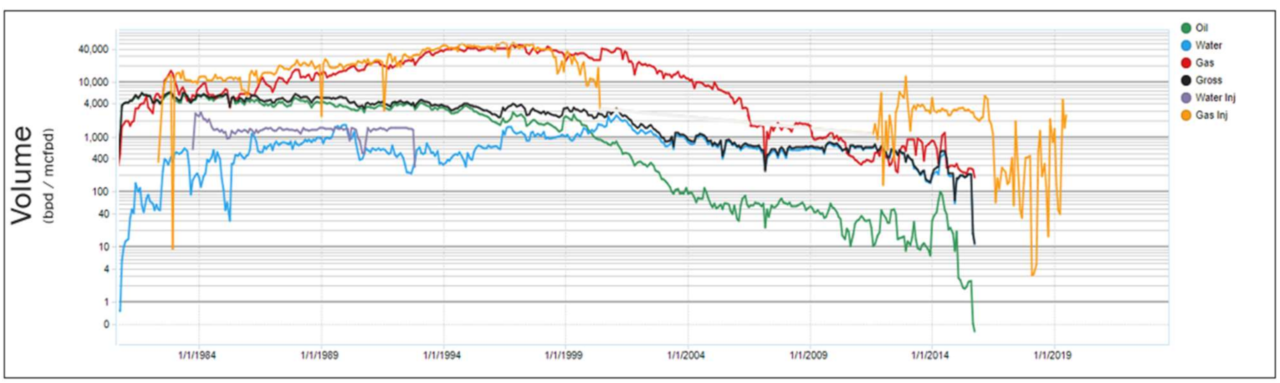
2. Performance data from operating the Monterey Formation A1-A2 oil and gas reservoir indicates no connection to an active aquifer.

   i. Historical production data (Figure 9) shows minimal water production, supporting limited aquifer influx.

   ii. Gas injection and subsequent gas blow-down (Figure 9) proves lateral and vertical confinement by demonstrating that gas did not migrate out of the reservoir.

   iii. Pressure in the reservoir is at 230 PSI, demonstrating minimal to no aquifer influx and subsequent increase in pressure.

**Figure 9: Monterey Formation A1-A2 production and injection data.**




### *Initial Conditions*

Initial model conditions (start of $CO_2$ injection) of the Monterey Formation A1-A2 reservoir have been established and verified over time as the reservoir has been developed for oil and gas production. Initial conditions for the model are given in Table 4.

**Table 4. Initial conditions.**

| Parameter | Value or Range | Units | Corresponding Elevation (ft MSL) | Data Source |
|---|---|---|---|---|
| Temperature | 240 | Fahrenheit | 8,300 | Fluid Analysis |
| Formation pressure | 200-300 | Pounds per square inch | 8,300 | Pressure Test |
| Fluid density | 61 | Pounds per cubic foot | 8,300 | Water analysis |
| Salinity | 25,000 | Parts per million | 8,300 | Water analysis |

### *Operational Information*

Details on the injection operation are presented in Table 5.

**Table 5. Operating details.**

| Operating Information | Injection Well 1 357-7R | Injection Well 2 355-7R |
|---|---|---|
| Location (global coordinates)<br>X<br>Y | <br>35.32802963<br>-119.5449982 | <br>35.33139038<br>-119.5441437 |
| Model coordinates (ft)<br>X<br>Y | <br>6,100,956.63<br>2,308,944.30 | <br>6,101,103<br>2,310,474 |
| No. of perforated intervals | 7 | 4 |
| Perforated interval (ft MSL)<br>Z top<br>Z bottom | <br>7,728<br>8,010 | <br>7,774<br>7,949 |
| Wellbore diameter (in.) | 7 | 7 |
| Planned injection period<br>Start<br>End | <br>02/01/2024<br>04/01/2039 | <br>02/01/2024<br>04/01/2039 |
| Injection duration (years) | 15 | 15 |
| Injection rate (t/day)* | 648 – 1,917 | 648 – 1,917 |

*If planned injection rates change year to year, add rows to reflect this difference, and include an average injection rate per year (or interval if applicable).

### *Fracture Pressure and Fracture Gradient*

Calculated fracture gradient and maximum injection pressure values are given in Table 6.

The Monterey Formation A1-A2 reservoir has been developed with assistance of gas and water injection to maintain reservoir pressure and improve oil recovery efficiency. As part of this process, California Resources Corporation (CRC) obtained Class II UIC approval from CalGEM. The Class II permit approval mandates that the maximum operating pressure gradient should not exceed 0.80 psi/foot unless additional testing indicates a higher gradient is appropriate.

CRC has also conducted tests to determine the fracture gradient for the injection zone. These results are consistent with data collected outside the field.

**Table 6: Summary of the fracture pressure data for the Monterey Formation A1-A2 reservoir.**

| Interval | Fracture Gradient PSI/foot | Fracture Pressure (PSI) at base of Reef Ridge Shale (8,403 feet) |
|---|---|---|
| Monterey Formation A1-A2 | 0.97 | 8,150 |

CTV will ensure that the injection pressure is beneath 90% of the fracture gradient at the shallowest point of the Reef Ridge Shale base in the AoR (Table 7) using the Monterey Formation A1-A2 fracture gradient. The planned maximum subsurface wellbore injection pressure for the project is 4,500 PSI.

**Table 7. Injection pressure details.**

| **Injection Pressure Details** | **Injection Well 1 357-7R** | **Injection Well 2 355-7R** |
|---|---|---|
| Fracture gradient (psi/ft) | 0.97 | 0.97 |
| Maximum injection pressure (90% of fracture pressure) (psi) | 7,335 | 7,335 |
| Elevation corresponding to maximum injection pressure (ft MSL) | 8,403 | 8,403 |
| Elevation at the top of the perforated interval (ft MSL) | 8,485 | 8,462 |
| Calculated maximum injection pressure at the top of the perforated interval (psi) | 7,407 | 7,387 |
| Planned maximum injection pressure / gradient (top of perforations) | 4,500 / 0.53 | 4,500 / 0.53 |

## Computational Modeling Results

### *Predictions of System Behavior*

The following maps (Figure 10) and cross-sections (Figure 11) show the computational modeling results and development of the $CO_2$ plume at four –time-steps. For all layers in the model and at all time-steps, the plume stays within the 2.1 square mile AoR. Within the first two years of injection, the AoR extent is largely defined. Thereafter, the $CO_2$ injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the $CO_2$ injectate remains as super-critical $CO_2$.

**Figure 10: Plan view showing the plume development through time for layer 15. Note that the plume does not change from 50 years post injection to 100 years post injection.**

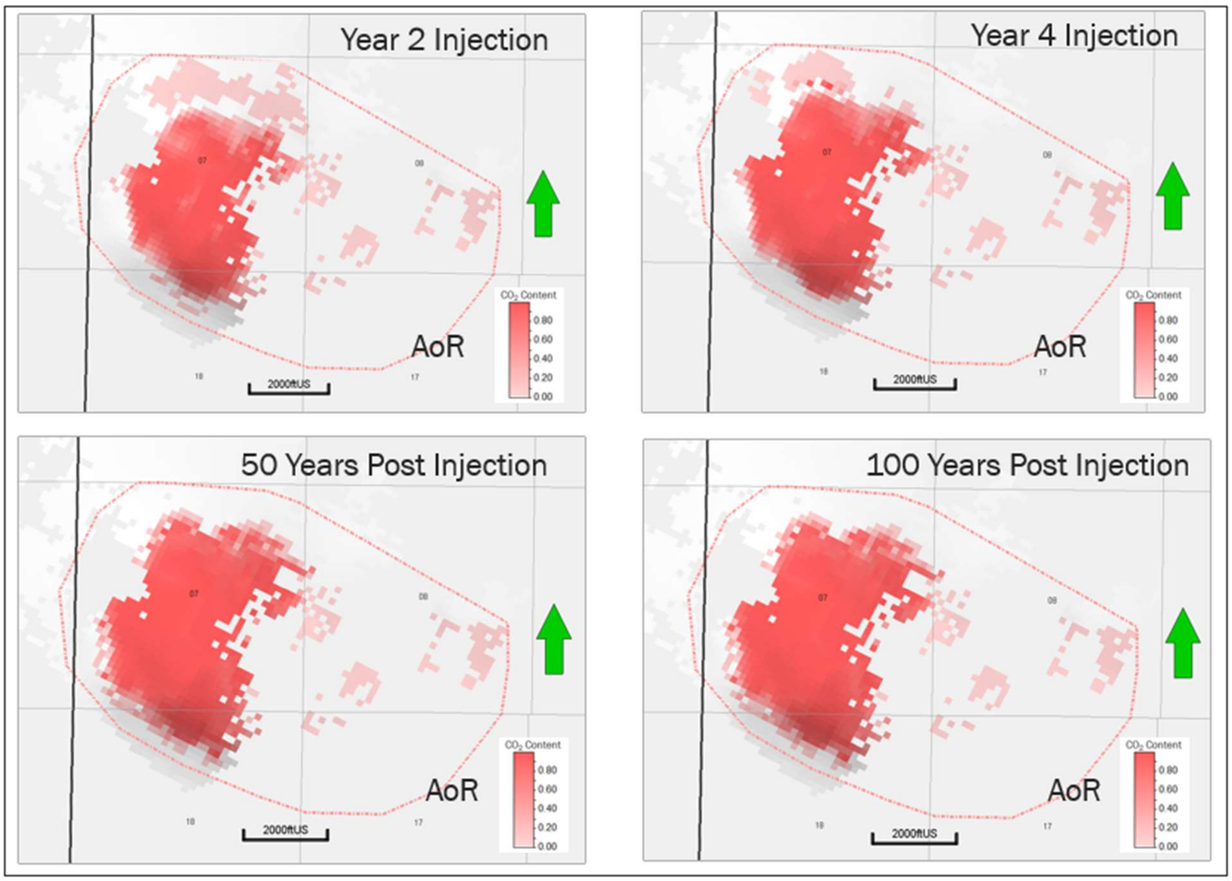
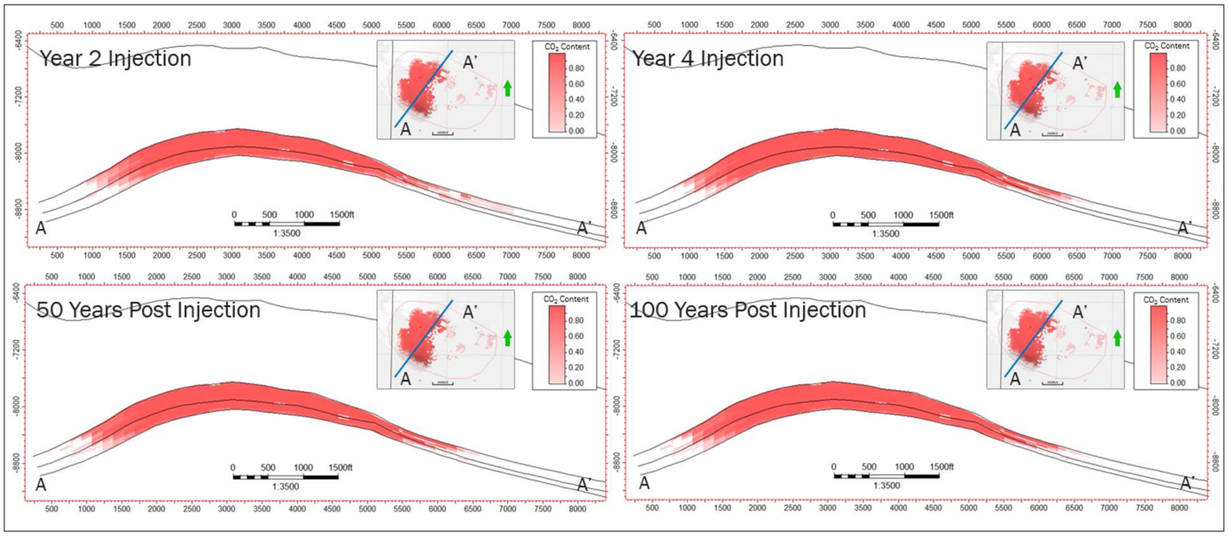
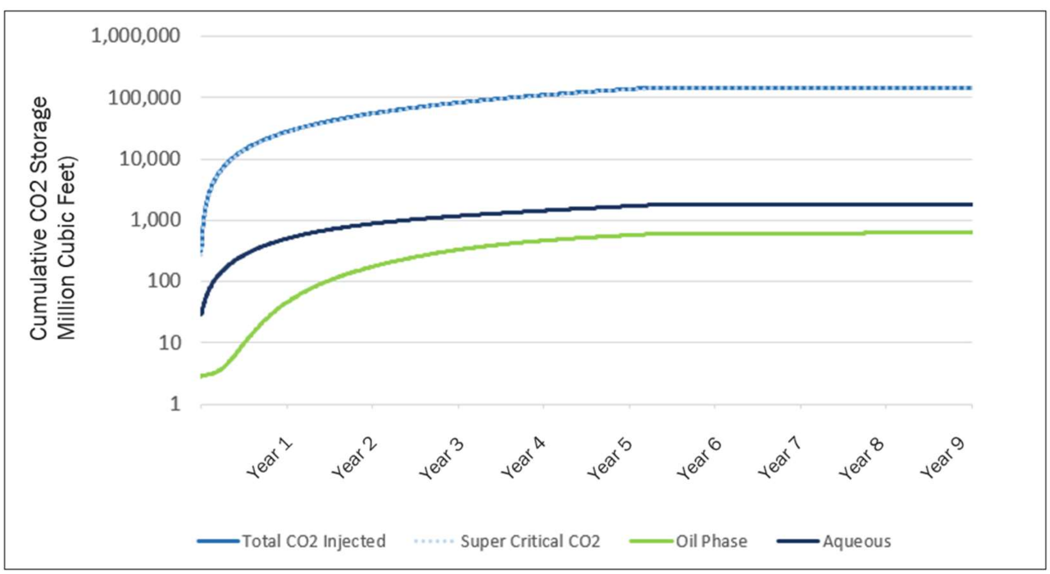


**Figure 11: Cross-sections showing the plume development through varying times through the project. Note that the plume does not change from 50 years post injection to 100 years post injection.**




$CO_2$ injected into the Monterey Formation A1-A2 reservoir will be soluble in both water and oil. Due to the low remaining saturation for oil and water in the depleted reservoir, total dissolved $CO_2$ in oil and water is only 0.5% and 1.3% of the $CO_2$ injected respectively. 98% of $CO_2$ injected is stored as super-critical $CO_2$. Figure 12 shows the cumulative storage for each of the mechanisms. After 5 years of injection, there is no additional change in the quantity of $CO_2$ dissolving in the oil and water.

**Figure 12: CO2 storage mechanisms in the reservoir.**

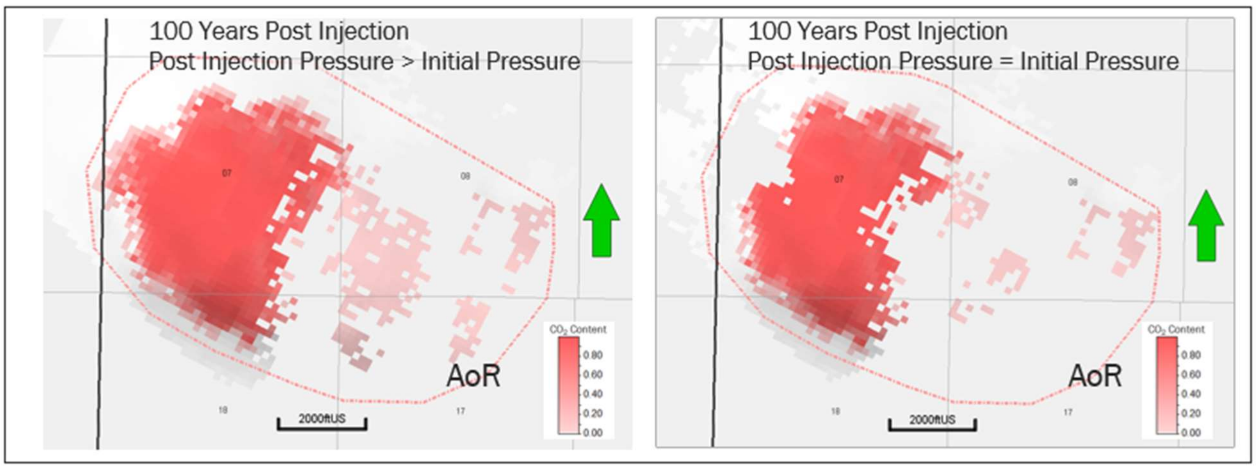


### *Model Calibration and Validation*

CRC has injected 175 BCF of gas into the Monterey Formation A1-A2 reservoir. This operational experience provides insight into reservoir injectivity and continuity. The plume model results were compared against the area of the reservoir that has been depleted by oil and gas operations.

As a computational model sensitivity, CTV maintained the injection rate for nine years, with an increase of the post-injection pressure and total $CO_2$ injected. At a final pressure of 5,750 psi, versus 4,000 psi, the reservoir can store 193 BCF of $CO_2$, an addition of 61 BCF $CO_2$. Figure 13 shows the difference in plume development at 100 years post injection. Note that the plume stays within the AoR, with increased $CO_2$ concentrations in cells in northwestern portion of the AoR.

**Figure 13: Plan view of plume development at layer 15 in the computational model.**




This scenario demonstrates that the AoR, as defined by the maximum extent of $CO_2$ injectate, is consistent with a larger volume of $CO_2$ injected. This provides confidence that the corrective action well review and potential impact to the Upper Tulare USDW is conservative.

## AoR Delineation

The AoR was determined by the largest extent of the $CO_2$ plume from computational modeling results. In the AoR scenario, $CO_2$ was injected into the depleted Monterey Formation A1-A2 reservoir until the reservoir pressure reached the discovery pressure of 4,000 PSI. Benefits of this operational strategy are that there is no increased pressure front beyond the original reservoir limits.

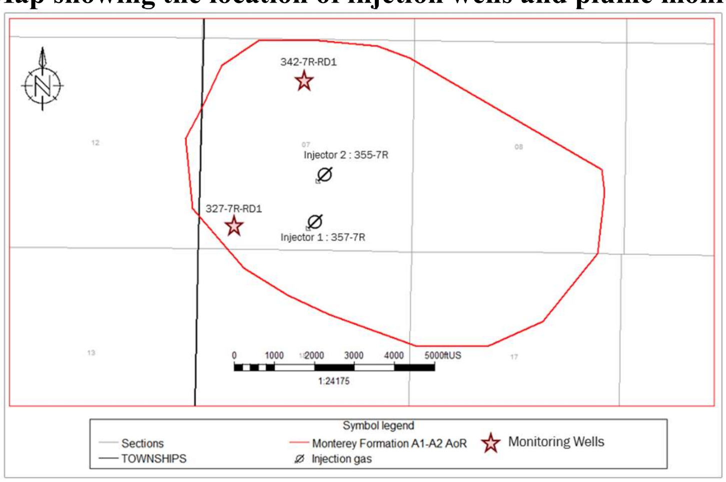
Figure 14 shows the AoR, injectors and offset monitoring wells. These monitoring wells were selected to both track the plume and measure reservoir pressure to understand the AoR and $CO_2$ plume development:

1. By integrating the reservoir pressure increase with the injected volume, CTV will complete a material balance to verify the pore volume and AoR edges.

2. $CO_2$ plume and water contact will be calculated from monitoring well pressure, $CO_2$ saturation and column height.

If the reservoir pressure increase associated with the injected volume does not follow the predicted trend from computational modeling, CTV will reassess the AoR.

**Figure 14: Map showing the location of injetion wells and plume monitoring wells.**




## Corrective Action

### *Tabulation of Wells within the AoR*

Wells within the AoR are associated with oil and gas development of the Monterey Formation. The Monterey Formation A1-A2 reservoir was discovered in 1973 and developed subsequently. As such, there are excellent records for wells drilled in the field. There have been no "un-documented" historical wells found during the over 40-year development history of the reservoir that includes injection of water and gas.

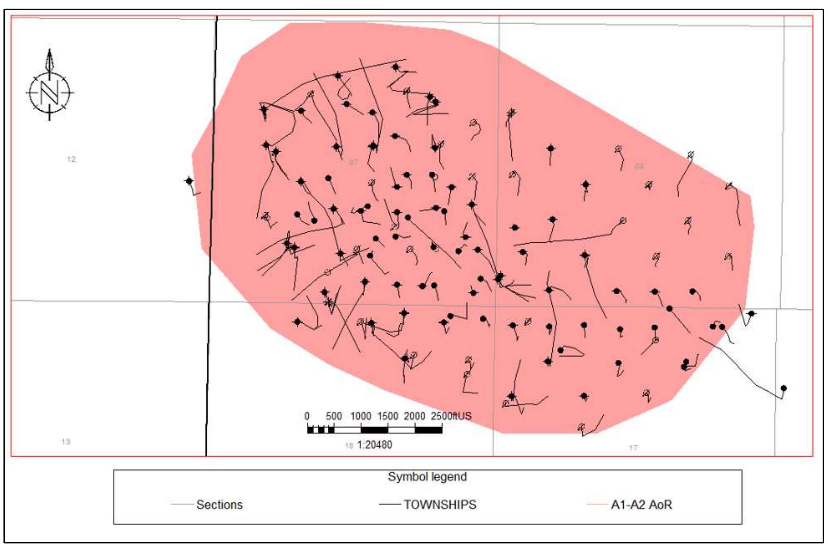
CTV accesses internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR. CalGEM rules govern well siting, construction, operation, maintenance, and closure for all wells in California oilfields. Detailed records describing the location and status of wells in the EHOF have been submitted to CalGEM as part of the drilling permits, workover activity, and existing Class II UIC permit applications. Table 8 is a summary of the AoR wells (Figure 15) in Appendix 1 showing the drill date, status, and type.

**Table 8: Wells in the AoR and associated well status. All wells in the AoR penetrate the Reef Ridge Confining Zone.**

| Status | Well Count |
|---|---|
| Inactive | 70 |
| Active | 42 |
| Plugged and Abandoned | 40 |
| **Total** | **152** |

Wells in the AoR with a status of oil producing, and water injection are active development wells completed underneath the Monterey Formation A1-A2 reservoir and associated with a CalGEM Class II approval within the A3-A6 sand intervals.

**Figure 15: Wells penetrating the Reef Ridge Shale confining layer and Monterey Formation A1-A2 sequestration reservoir reviewed for corrective action.**




*Wells Penetrating the Confining Zone*

The depth of the confining zone in each of the wells penetrating the Reef Ridge shale was determined through open-hole well logs utilizing the deviation survey. All wells in the AoR penetrate the Reef Ridge Shale confining zone. Table 8 is a summary of the AoR wells in Appendix 1 showing the drill date, status, type, and depth to Reef Ridge Shale confining zone.

As part of ongoing UIC processes, well condition, mechanical integrity and data completeness is routinely reviewed with CalGEM. The last review for the wells associated with the AoR well list occurred in Q1 2021.

The corrective action assessment included the generation of detailed wellbore/casing diagrams for each well (Appendix 1), determination of cement tops for each casing string, review of open perforations and cement plug depths. CTV can demonstrate that the USDW is protected and that with the abandonment of 14 wells, the Monterey Formation A1-A2 reservoir will be isolated.

Protection of USDW

For the Elk Hills A1-A2 project CTV assessed the protection of the USDW by all wellbores that penetrate the confining Reef Ridge Shale. A wells did not need corrective action that met the three criteria below:

1. Surface or intermediate casing over the USDW.
2. Cement over the USDW.
3. Cement in the annulus:
    a. Intermediate casing – cement above the above the surface casing shoe.
    b. Reef Ridge Shale – cement in annulus of production casing above the confining Reef Ridge Shale.

All wells within the AoR meet the criteria above, ensuring protection of the USDW.

Monterey Formation A1-A2 Isolation

Wells that will not be used for the Elk Hills A1-A2 Storage project that penetrate and are currently perforated in the Monterey Formation A1-A2 or the Etchegoin Formation will be abandoned prior to injecting $CO_2$. The abandonment of these wells is considered to be normal operating procedures to manage and minimize liabilities. There are 14 wells that meet this criterion as shown in Table 9.

**Table 9: Wells to be abandoned prior to injection as part of asset retirement obligations.**

| | |
|---|---|
| 342H-7R-RD1 | 353A-7R |
| 367X-7R | 335X-7R |
| 368A-7R | 336-7R |
| 374A-7R-RD1 | 348H-7R-RD1 |
| 367A-7R | 354X-7R |
| 355-8R | 361H-8R-RD3 |
| 365-7R | 313-17R |

### *Plan for Site Access*

CTV operates and owns 100% of the surface, mineral and pore space rights for the project where all activities will take place. As such, site access has been guaranteed for the duration of the project and for post-injection monitoring.

### *Corrective Action Schedule*

Corrective action for all wells withing the AoR will be completed before $CO_2$ is injected in the reservoir. This will ensure that $CO_2$ is confined to the injection zone for the entire AoR, protecting the overlying USDW and ensuring confinement.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

## Reevaluation Schedule and Criteria

### *AoR Reevaluation Cycle*

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, $CO_2$ injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

1. Pressure data from monitoring wells that constrain and define plume development.

2. $CO_2$ content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.

3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and $CO_2$ concentration data in 1 and 2 above.

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

### *Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation*

An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

1. Change in operations such as an increase in injection rates, or injection pressure.

2. Difference between the computation modeling and observed plume development:

    a. Unexpected changes in fluid constituents or pressure outside the Monterey Formation A1-A2 reservoir that are not related to well integrity.

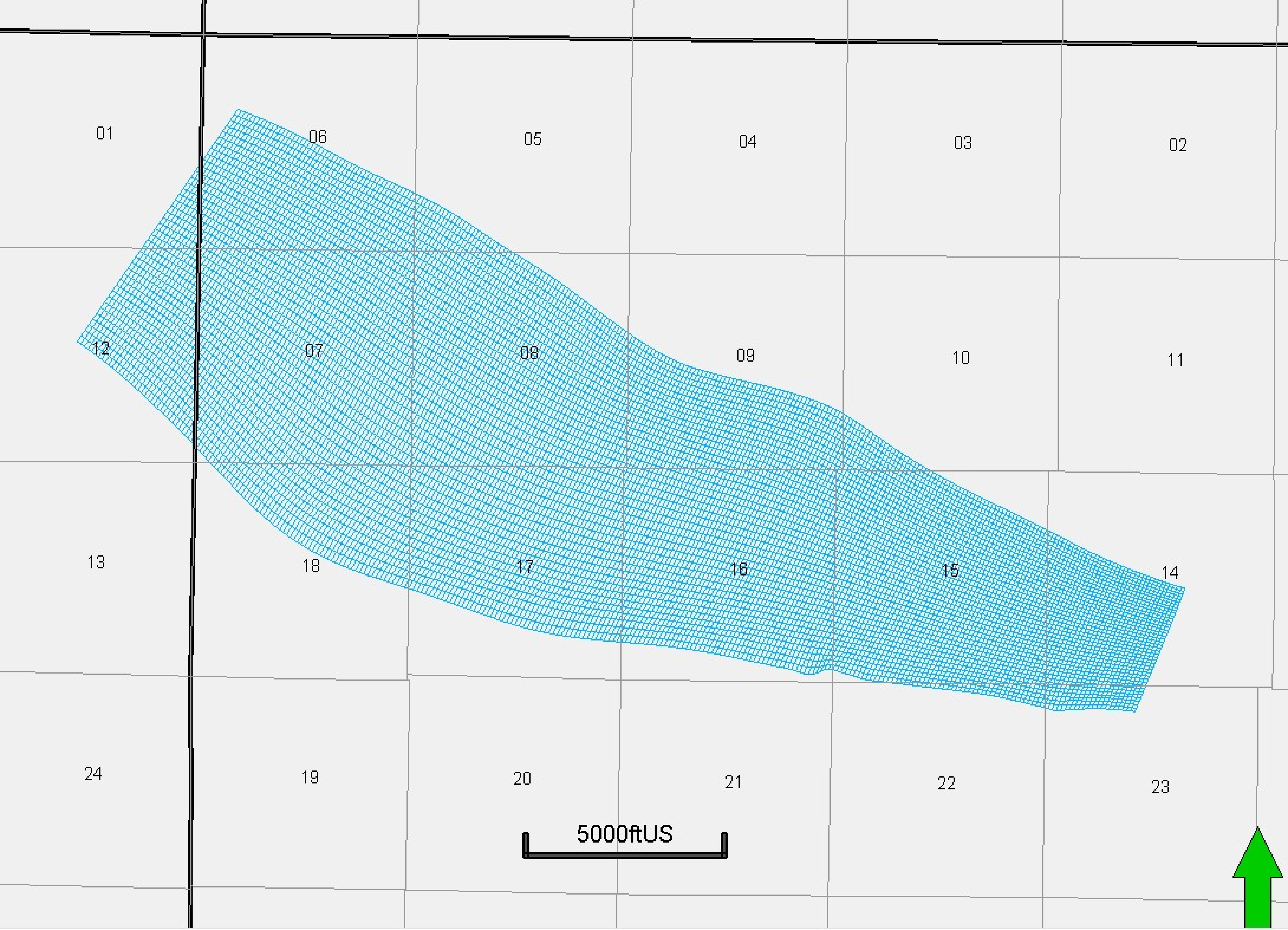
b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results.

3. Seismic monitoring anomalies that are indicative of:

a. The presence of faults near the confining zone that indicates propagation into the confining zone.

b. Events reasonably associated with $CO_2$ injection that are greater than M3.5.

CTV will discuss any such events with the UIC Program Director to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan.


01
06
05
04
03
02
12
07
08
09
10
11
13
18
17
16
15
14
24
19
20
21
22
23
5000ftUS

## CLASS VI CRITICAL PRESSURE CALCULATION

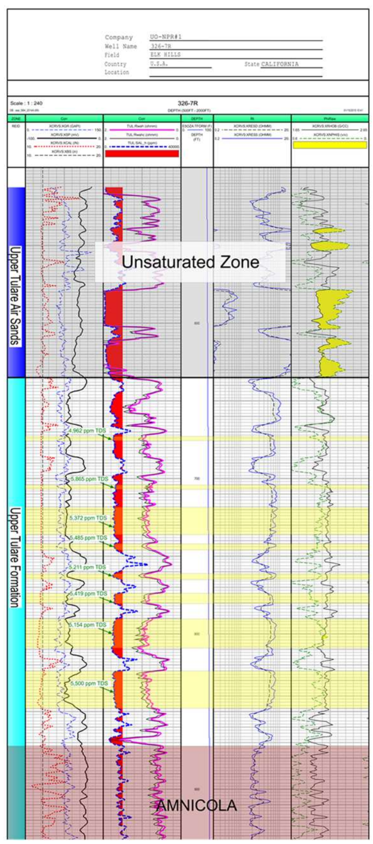
## INJECTION WELL 357-7R
## ELK HILLS A1-A2 PROJECT

**Critical Pressure Calculation**

Upper Tulare USDW Inputs

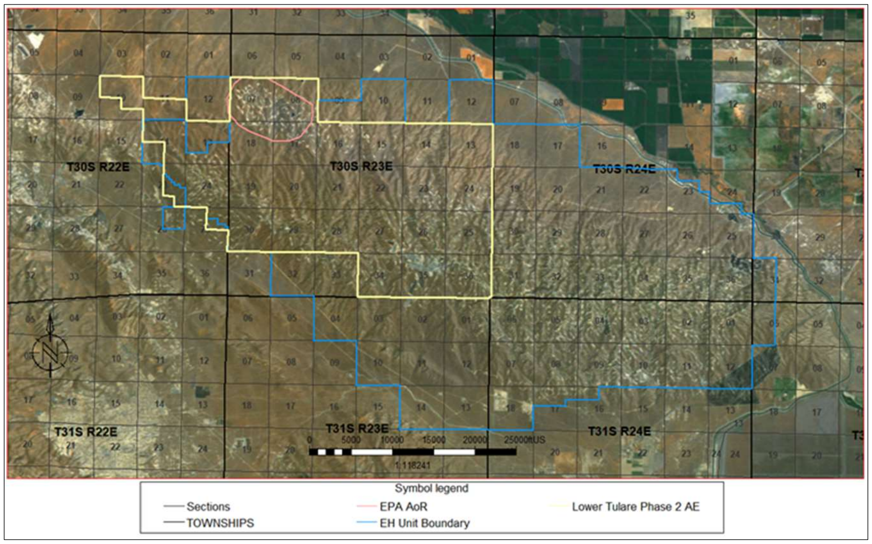
The unconfined Upper Tulare Formation USDW within the area of review (AoR) onlaps onto the anticline structure. As such, there are areas within the project with no USDW. The hydraulic head and depth is based on the 326-7R type well (Figure 1). Water levels with the Upper Tulare USDW are variable and have historically been falling. As such, water presence, depths and thickness for the Upper Tulare USDW are conservative. Calculated salinities are annotated for each sand in the Upper Tulare.

**Figure 1: Well 326-7R type well of the Upper Tulare Formation USDW.**




The Lower Tulare Formation has been approved as an exempt aquifer, the area approved is shown in Figure 2. North of the AoR the USDW is not defined as the Upper Tulare Formation but the Lower Tulare.

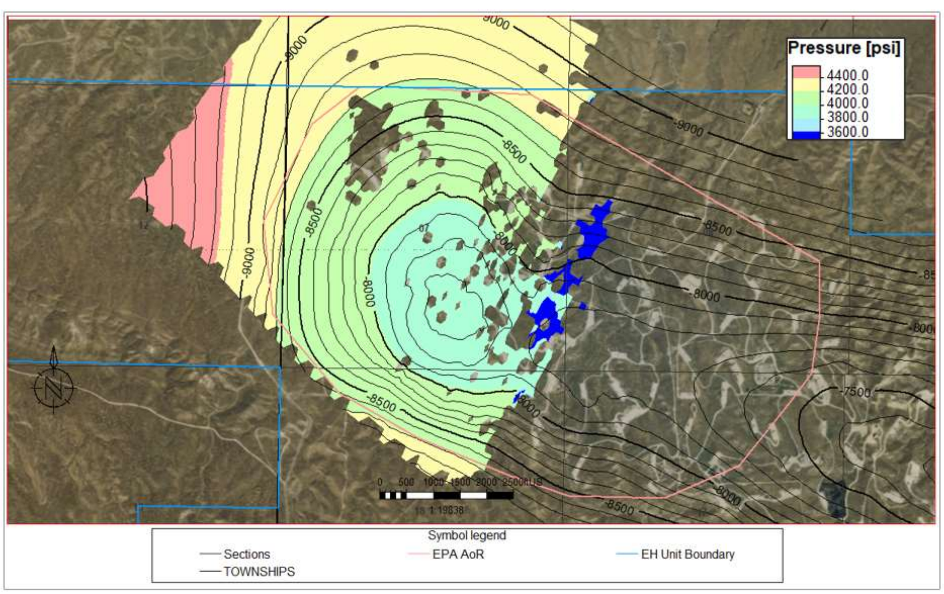
**Figure 2: Lower Tulare aquifer exemption area.**




Computational Modeling Monterey Formation A1-A2 Pressure

The Monterey Formation A1-A2 reservoir has been depleted by oil and gas production. Currently the pressure of the reservoir is 200-300 PSI. The final $CO_2$ reservoir pressure will be at or below the initial reservoir conditions (4,000 PSI). The pressure for the reservoir post injection based on computational modeling results is shown in Figure 3.

**Figure 3: Monterey Formation A1-A2 structure map showing computational modeling reservoir pressure post-injection (top layer of the model). In the eastern portion of the AoR the reservoir sands grade to shale for the top layer of the model so the reservoir pressure is not determined.**

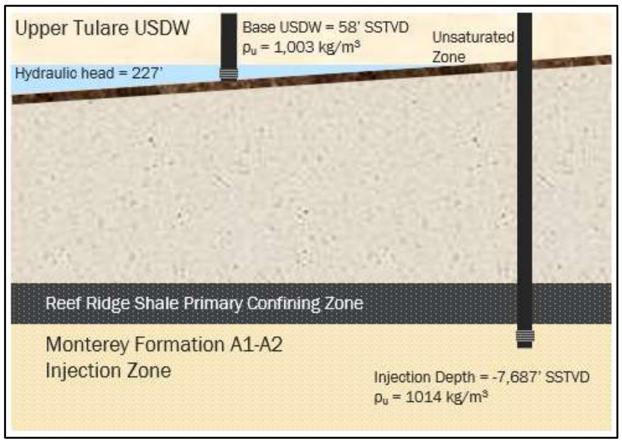


Critical Pressure Calculation

Using the equation below, the critical pressure for the Monterey Formation A1-A2 reservoir is 3,400 PSI (Figure 4).

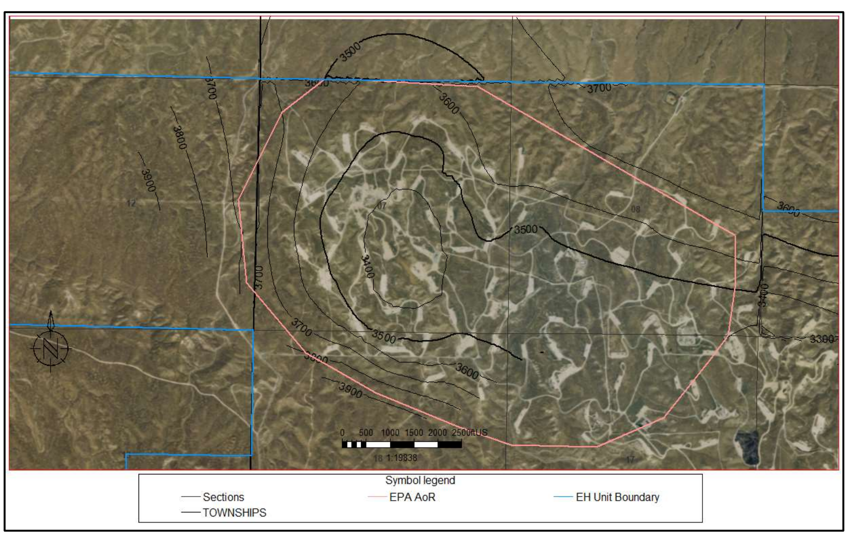
$$\frac{P_{i,f}}{\rho_i g} + z_i = \frac{P_u}{\rho_u g} + z_u$$

**Figure 4: Schematic section of the storage site with inputs to critical pressure calculation. Values for the USDW are based on the 326-7R well. The injection depth is based on the 357-7R injector. Using data from wells 357-7R injector and 326-7R the critical pressure is 3,400 PSI.**




Critical pressure calculated for the reservoir is shown in Figure 5 using the Monterey Formation A1-A2 reservoir top and Base USDW.

**Figure 5: Critical pressure map in PSI using the Base USDW and Monterey Formation A1-A2 surfaces. Note that across the Elk Hills boundary the base of USDW is defined by the Lower Tulare instead of the Upper Tulare, resulting in a change in the contours.**



Summary of AoR

The final pressure of the Monterey Formation A1-A2 reservoir will be at or below the initial reservoir pressure to ensure that $CO_2$ occupies the same pore space that was initially saturated with hydrocarbons and the pressure front is at equilibrium with initial conditions. As such, CTV defines the AoR as the aerial extent of the $CO_2$ plume.

**CLASS VI MODEL FACIES**

**ELK HILLS A1-A2 PROJECT**

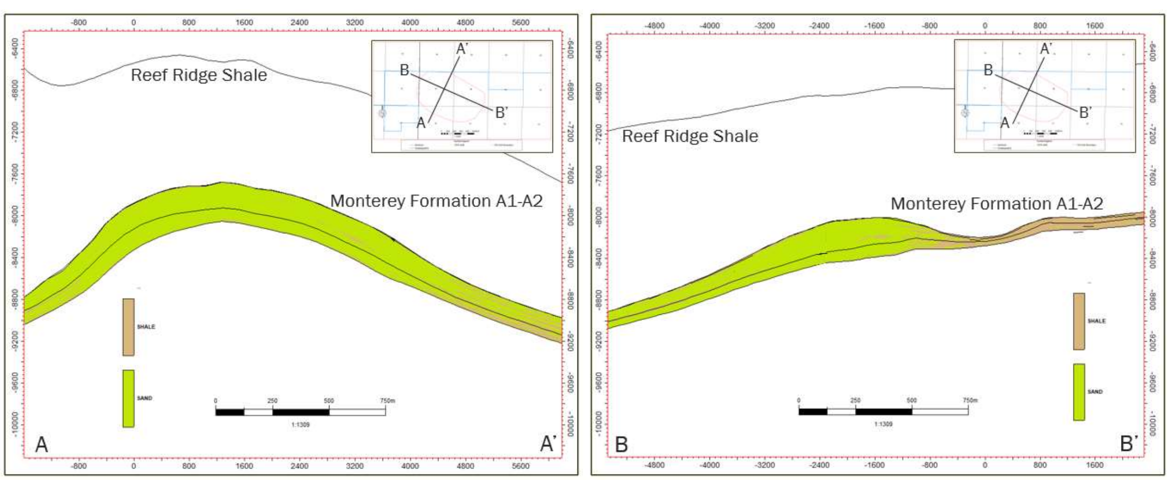
Site Geology and Hydrology

The Northwest Stevens Field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation A1-A2, present in the northwestern portion of the field, pinch out towards the southeast (Figure 1, cross-section A-A'), while the lowermost sands, are present across the entire structure.

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation A1-A2, but for all Monterey accumulations in the greater Elk Hills area.

Below are cross-section showing facies for the static geological model.

**Figure 1: Facies cross-section.**



# CLASS VI MODEL FACIES

# ELK HILLS A1-A2 PROJECT

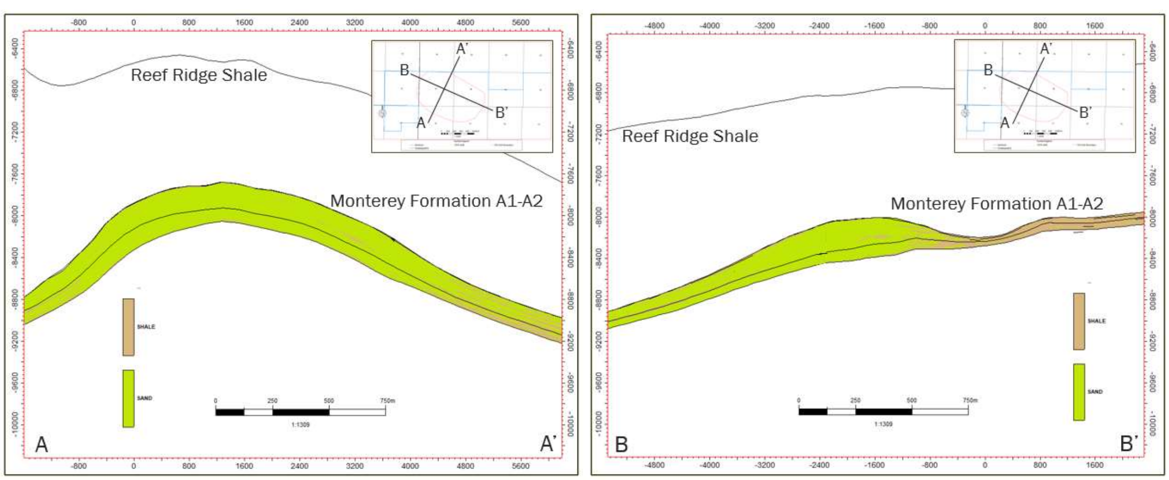
## Site Geology and Hydrology

The Northwest Stevens Field is a northwest-southeast trending anticlinal structure located in the Elk Hills Oil Field within the San Joaquin Valley of California, producing oil and gas from the Miocene-aged Monterey Formation. The reservoir sands are composed of a series of stacked turbidite sands, interbedded with siliceous shales and clays. The Monterey Formation A1-A2, present in the northwestern portion of the field, pinch out towards the southeast (Figure 1, cross-section A-A'), while the lowermost sands, are present across the entire structure.

The Monterey Formation sands are bound above by the regional Reef Ridge Shale, and below by the Lower Antelope Shale Member of the Monterey Formation. The Reef Ridge Shale is a deep marine, clay-rich interval, deposited regionally with average gross thicknesses of ~1,000', and has a very low matrix permeability. Its competence in confining upward fluid movement is established by its demonstrated historical performance as the regional seal for hydrocarbon accumulation within the Monterey Formation, not only for the Monterey Formation A1-A2, but for all Monterey accumulations in the greater Elk Hills area.

Below are cross-section showing facies for the static geological model.

**Figure 1: Facies cross-section.**



File size too large, available upon request.

Please contact Travis Hurst at 661-342-2409 or travis.hurst@crc.com

There no internal boundaries within the AoR or the modeled area.

Please contact Travis Hurst at 661-342-2409 or travis.hurst@crc.com

## CLASS VI FRACTURE GRADIENT AND OPERATING PRESSURE

## INJECTION WELLS 357-7R AND 355-7R

## ELK HILLS A1-A2 PROJECT

### Fracture Pressure and Fracture Gradient

The Monterey Formation A1-A2 reservoir has been developed with assistance of gas and water injection to maintain reservoir pressure and improve oil recovery efficiency. As part of this process, California Resources Corporation (CRC) obtained Class II UIC approval from CalGEM. The Class II permit approval mandates that the maximum operating pressure gradient should not exceed 0.80 psi/foot unless additional testing indicates a higher gradient is appropriate.

CRC has also conducted tests to determine the fracture gradient for the injection zone. These results are consistent with data collected outside the field. Reservoir fracture gradient and the fracture pressure based on the shallowest Reef Ridge Shale depth in the AoR are shown in Table 1. The fracture gradient is based on a Monterey Formation A1-A2 fracture test in the 327-7R-RD1 well (Table 1).

**Table 1: Summary of the fracture pressure data for the Monterey Formation A1-A2 reservoir.**

| Interval | Fracture Gradient (PSI/foot) | Fracture Pressure (PSI) at base of Reef Ridge Shale (8,403 feet) | 90% of Fracture Pressure (PSI) |
|---|---|---|---|
| Monterey Formation A1-A2 | 0.97 | 8,150 | 7,335 |

Carbon TerraVault 1 LLC will ensure that the injection pressure is beneath 90% of the fracture gradient at the shallowest point of the Reef Ridge Shale base in the AoR (Table 2) using the Monterey Formation A1-A2 fracture gradient. The planned maximum subsurface wellbore injection pressure for the project is 4,500 PSI (Table 2).

**Table 2: Injection pressure details.**

| Injection Pressure Details | Injection Well 1 357-7R | Injection Well 2 355-7R |
|---|---|---|
| Fracture gradient (psi/ft) | 0.97 | 0.97 |
| Maximum injection pressure (90% of fracture pressure) (psi) | 7,335 | 7,335 |
| Elevation corresponding to maximum injection pressure (ft MSL) | 8,403 | 8,403 |
| Elevation at the top of the perforated interval (ft MSL) | 8,485 | 8,462 |
| Calculated maximum injection pressure at the top of the perforated interval (psi) | 7,407 | 7,387 |
| Planned maximum injection pressure / gradient (top of perforations) | 4,500 / 0.53 | 4,500 / 0.53 |

# CLASS VI FRACTURE GRADIENT AND OPERATING PRESSURE

# INJECTION WELLS 357-7R AND 355-7R

# ELK HILLS A1-A2 PROJECT

## Fracture Pressure and Fracture Gradient

The Monterey Formation A1-A2 reservoir has been developed with assistance of gas and water injection to maintain reservoir pressure and improve oil recovery efficiency. As part of this process, California Resources Corporation (CRC) obtained Class II UIC approval from CalGEM. The Class II permit approval mandates that the maximum operating pressure gradient should not exceed 0.80 psi/foot unless additional testing indicates a higher gradient is appropriate.

CRC has also conducted tests to determine the fracture gradient for the injection zone. These results are consistent with data collected outside the field. Reservoir fracture gradient and the fracture pressure based on the shallowest Reef Ridge Shale depth in the AoR are shown in Table 1. The fracture gradient is based on a Monterey Formation A1-A2 fracture test in the 327-7R-RD1 well (Table 1).

**Table 1: Summary of the fracture pressure data for the Monterey Formation A1-A2 reservoir.**

| Interval | Fracture Gradient (PSI/foot) | Fracture Pressure (PSI) at base of Reef Ridge Shale (8,403 feet) | 90% of Fracture Pressure (PSI) |
|---|---|---|---|
| Monterey Formation A1-A2 | 0.97 | 8,150 | 7,335 |

Carbon TerraVault 1 LLC will ensure that the injection pressure is beneath 90% of the fracture gradient at the shallowest point of the Reef Ridge Shale base in the AoR (Table 2) using the Monterey Formation A1-A2 fracture gradient. The planned maximum subsurface wellbore injection pressure for the project is 4,500 PSI (Table 2).

**Table 2: Injection pressure details.**

| Injection Pressure Details | Injection Well 1 357-7R | Injection Well 2 355-7R |
| --- | --- | --- |
| Fracture gradient (psi/ft) | 0.97 | 0.97 |
| Maximum injection pressure (90% of fracture pressure) (psi) | 7,335 | 7,335 |
| Elevation corresponding to maximum injection pressure (ft MSL) | 8,403 | 8,403 |
| Elevation at the top of the perforated interval (ft MSL) | 8,485 | 8,462 |
| Calculated maximum injection pressure at the top of the perforated interval (psi) | 7,407 | 7,387 |
| Planned maximum injection pressure / gradient (top of perforations) | 4,500 / 0.53 | 4,500 / 0.53 |

## CLASS VI GEOMECHANICAL MODELING

## INJECTION WELL 357-7R
## ELK HILLS A1-A2 PROJECT

### Geomechanical Modeling

Overview

A finite element geomechanics module, GEOMECH, coupled with Computer Modeling Group's (CMG) equation of state compositional reservoir simulator (GEM), was used to model failure of the Reef Ridge Shale due to increasing pressure in the underlying reservoir by $CO_2$ injection. A modified Barton-Bandis model can be used to allow $CO_2$ to escape from the storage reservoir through the cap rock to overburden layers. The location and direction of fractures in a grid block are determined via normal fracture effective stress computed from the geomechanics module.

A generic two-dimensional model was constructed to represent the reservoir, confining layer, and overburden formations. $CO_2$ is injected through an injector located at the center of the X-Z plane and perforated throughout the reservoir. Increasing pressure in the reservoir is expected to push up and bend the overlying cap rock to create a tensile stress around the high-pressure region. As gas continues to be injected, the normal effective stress in the cap rock is expected to continually decrease. When the cap rock reaches a threshold value, defined as zero in this model, a crack will appear in the cap rock and the Barton-Bandis model will allow $CO_2$ to leak from the storage reservoir.

Results

Failure pressures for the four scenarios are given in Table 1. The value for the reduced injection case was extrapolated from the pressure at a stress of about 10 PSI These results suggest that the Reef Ridge Shale can tolerate a pressure at the base of 7,500 PSI or more without failure.

**Table 1: Geomechanical modeling results for four scenarios.**

| GEOMECHANICAL SCENARIO RESULTS | |
|---|---|
| **SCENARIO** | **FAILURE PRESSURE, psia** |
| BASE CASE | 8306 |
| REDUCED YOUNG'S MODULUS | 8388 |
| REDUCED INJECTION RATE | 8340 |
| THINNER CAP ROCK | 7600 |

Description

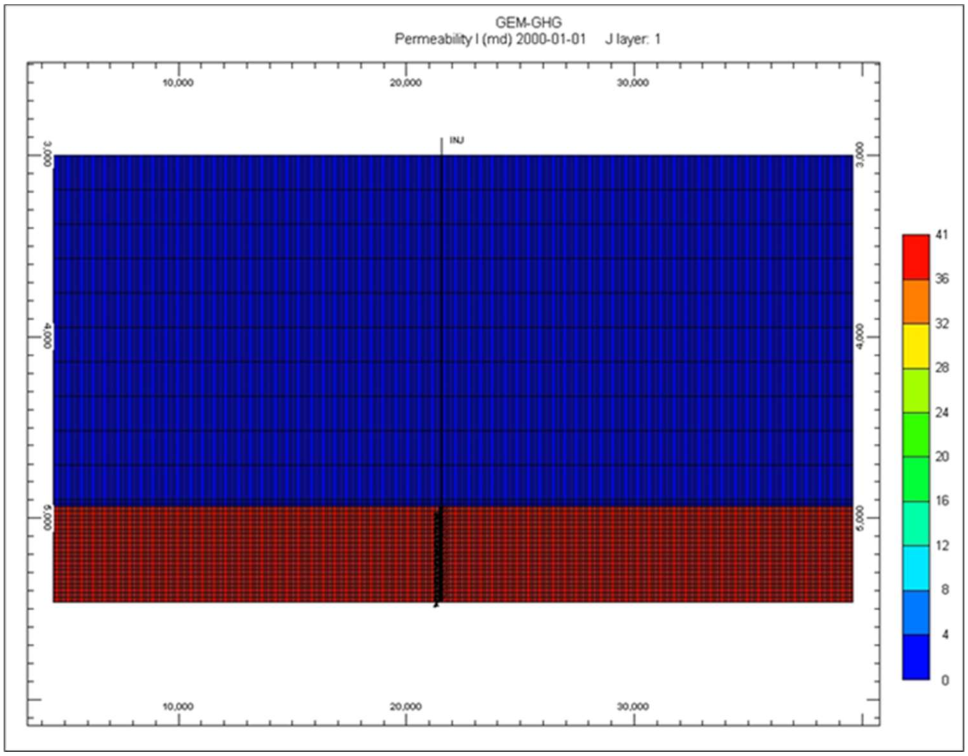
A 2-D cross-section model with 411 grid blocks in the X-direction and 33 grid blocks in the Z-direction was built encompassing a length of 43,100 feet and a thickness of 2,460 feet. This model is shown in Figure 1.

In the base model, the cap rock is 1,935 feet thick with a Young's modulus of 9E05 psi and a Poisson's ratio of 0.23. The reservoir is 525 feet thick with a Young's modulus of 7.25E05 and a Poisson's ratio of 0.25. Horizontal permeability is 1e-07 md in the cap rock and 40.5 md in the reservoir. The vertical to horizontal permeability ratio is 0.25. A constant porosity of 0.25 is used in all zones.

The reservoir is constrained at the bottom but allowed to move at the top and sides. The horizontal direction unconstrained boundary is used to cope with open regions on both the left and right of the modeled portion of the reservoir.

The injector was constrained to inject 30 million cubic feet per day of $CO_2$ with a maximum injection pressure of 10,000 PSI.

**Figure 1: Geomechanics Model.**

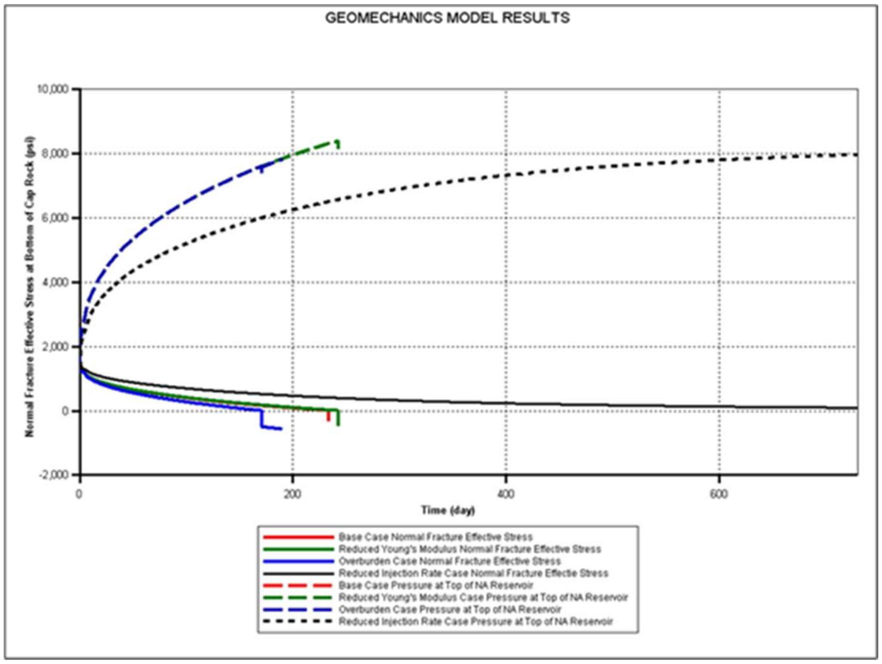



Scenarios Modeled

Four scenarios were modeled in this study. In the base case, the cap rock has a Young's modulus of 9E05 PSI. To model uncertainty in the cap rock Young's modulus, a second case was run with a value of 8E05 PSI. In the third case, the impact of a thinner cap rock was modeled by assigning a confining layer of 795 feet. In the fourth case, sensitivity to injection rate was studied by reducing the injection rate to 20 million cubic feet per day.

Figure 2 gives the change in the normal fracture effective stress in the bottom cap rock layer and the pressure in the top layer of the reservoir with time for each scenario. The failure pressure is defined as the value at which the effective stress is zero. In the reduced injection rate case the stress stopped decreasing at about 10 PSI, due to $CO_2$ bleeding into the cap rock despite the very low vertical permeability.

**Figure 2: Normal Fracture Stress and Pressure for Geomechanics Cases.**



# CLASS VI GRID DESCRIPTION
# ELK HILLS A1-A2 PROJECT

Model Domain

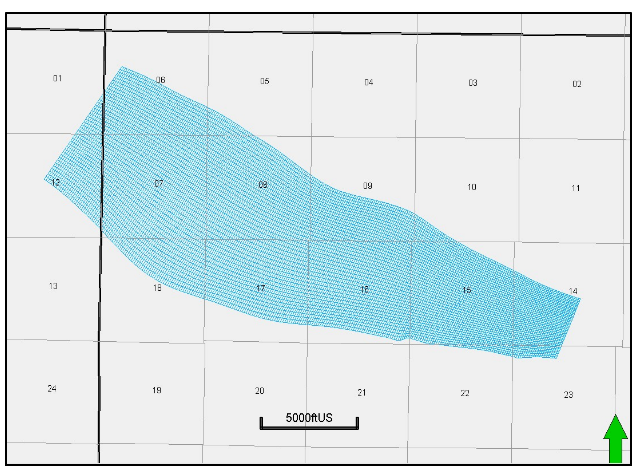
A static geological model developed with Schlumbergers Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in Table 1.

**Table 1. Model domain information.**

| | | | |
|---|---|---|---|
| **Coordinate System** | State Plane | | |
| **Horizontal Datum** | NAD 83 | | |
| **Coordinate System Units** | Feet | | |
| **Zone** | CA83-VF | | |
| **FIPSZONE** | 0405 | **ADSZONE** | 3376 |
| **Coordinate of X min** | 6,095,241.81 | **Coordinate of X max** | 6,122,433.26 |
| **Coordinate of Y min** | 2,302,015.15 | **Coordinate of Y max** | 2,316,903.12 |
| **Elevation of bottom of domain** | -10,426.35 | **Elevation of bottom of domain** | -6,670.36 |

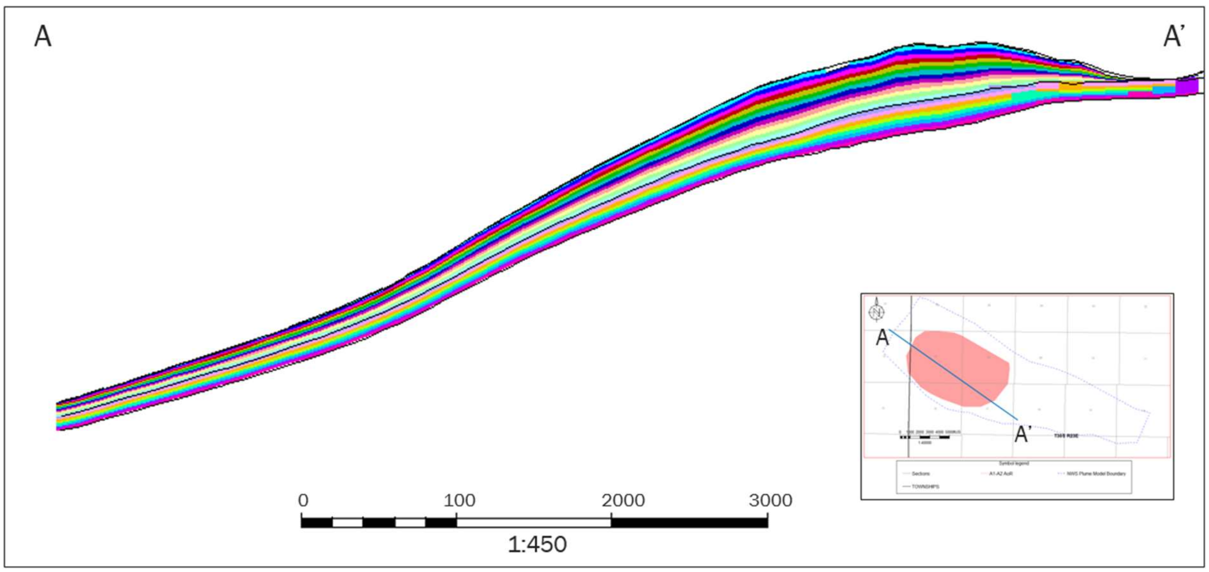
The geo-cellular grid is uniformly spaced throughout the 6.4 square mile model area (Figure 1) at 150 feet x 150 feet. The model is oriented at 55 degrees, which is aligned with both the structural trend of the anticline and the depositional environment. Model boundaries were selected to define plume extent and the peripheral area of elevated pressure.

**Figure 1: Plan view of the model boundary showing the extent of the CO2 plume that defines the AoR.**



The reservoir has been separated into two zones, A1 and A2 sands, with 8 and 13 layers (Figure 2) respectively and an average grid cell height of 11.5 feet. Grid resolution is a balance between simulation run-time and retaining reservoir heterogeneity for assessing $CO_2$ movement. Well data that defines the stratigraphy also defines the structure of the Monterey Formation A1-A2 storage reservoir. Each well drilled has a deviation survey used to establish the measured depth and depth sub-sea of each surface.

**Figure 2: Static model layering of the Monterey Formation A1-A2 reservoir. The stratigraphic units either pinch-out up-dip or reservoir sands transition to shale.**

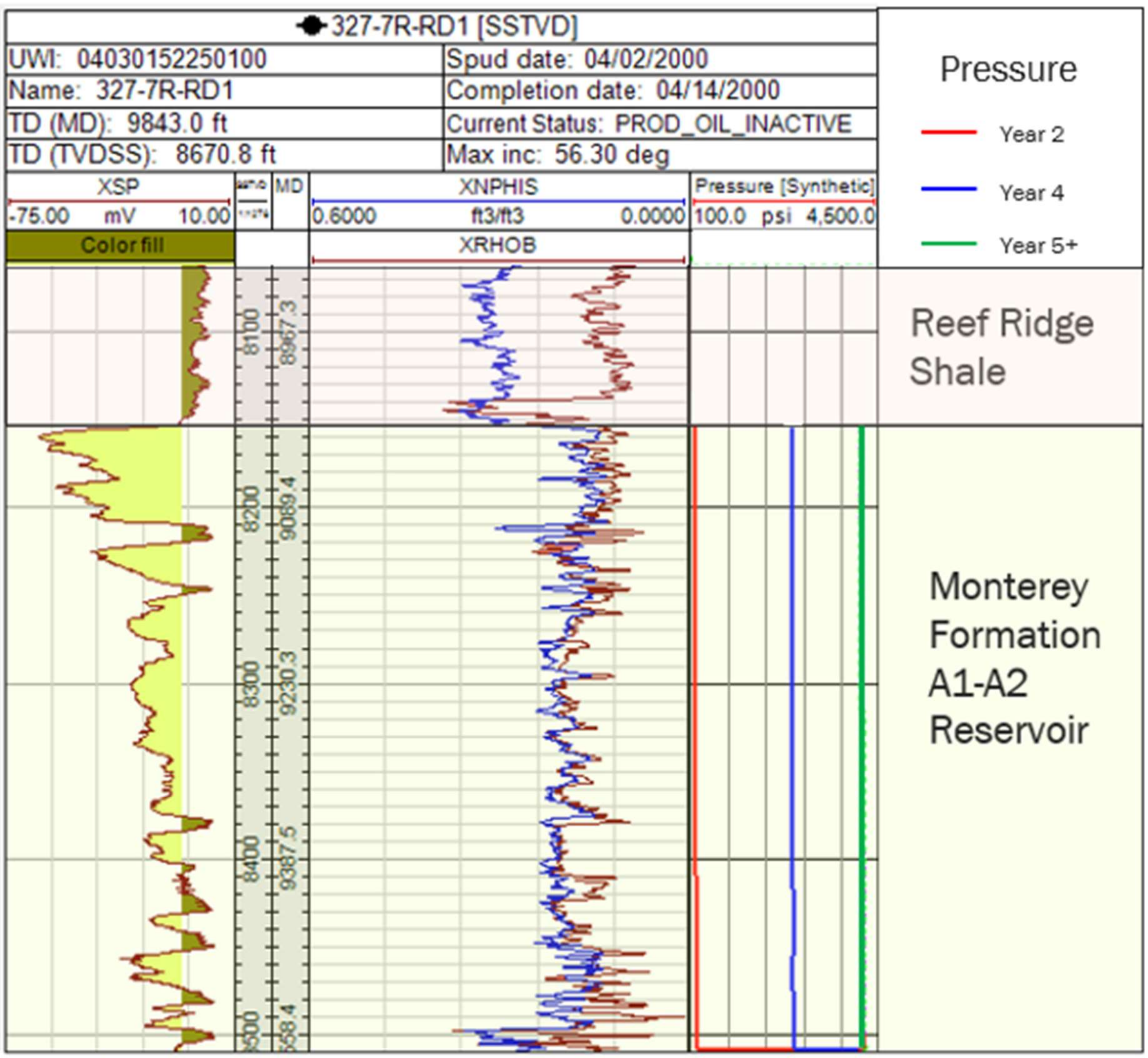


Grid file size too large to be uploaded.

Please contact Travis Hurst at 661-342-2409 or travis.hurst@crc.com

**CLASS VI MONITORING WELL**
**ELK HILLS A1-A2 PROJECT**

Monitoring well 327-7R-RD1 showing pressure change through time.



# CLASS VI PERMEABILITY IMAGES
# ELK HILLS A1-A2 PROJECT

## Permeability Distribution

Figure 1 shows porosity and permeability histograms for the Monterey Formation A1-A2 sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 2 shows the permeability and porosity distribution in cross-section A-A'. Reservoir quality is the highest at the top of the anticline, porosity and permeability are lower on the edges.

**Figure 1: Monterey Formation A1-A2 sands porosity and permeability distribution in the static model.**

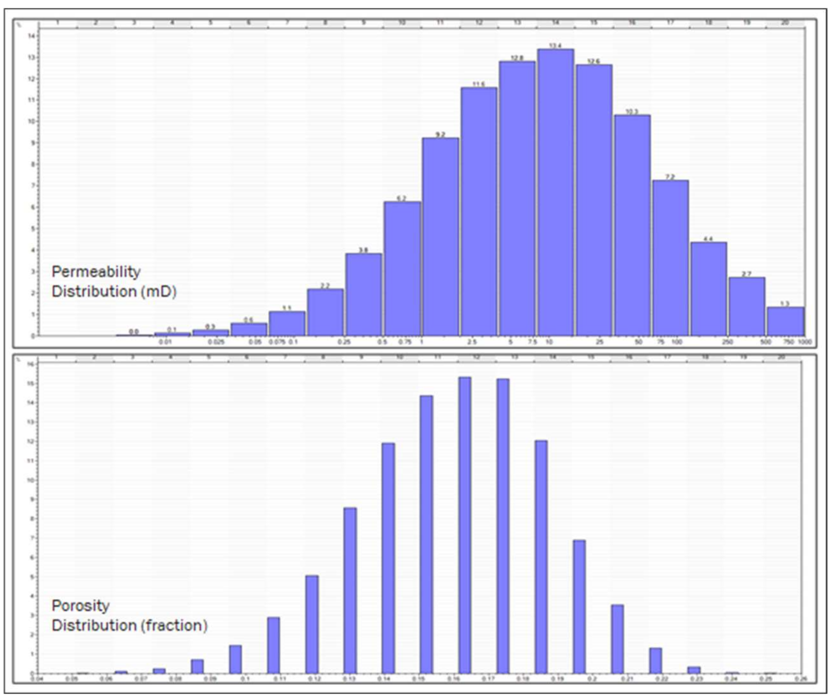
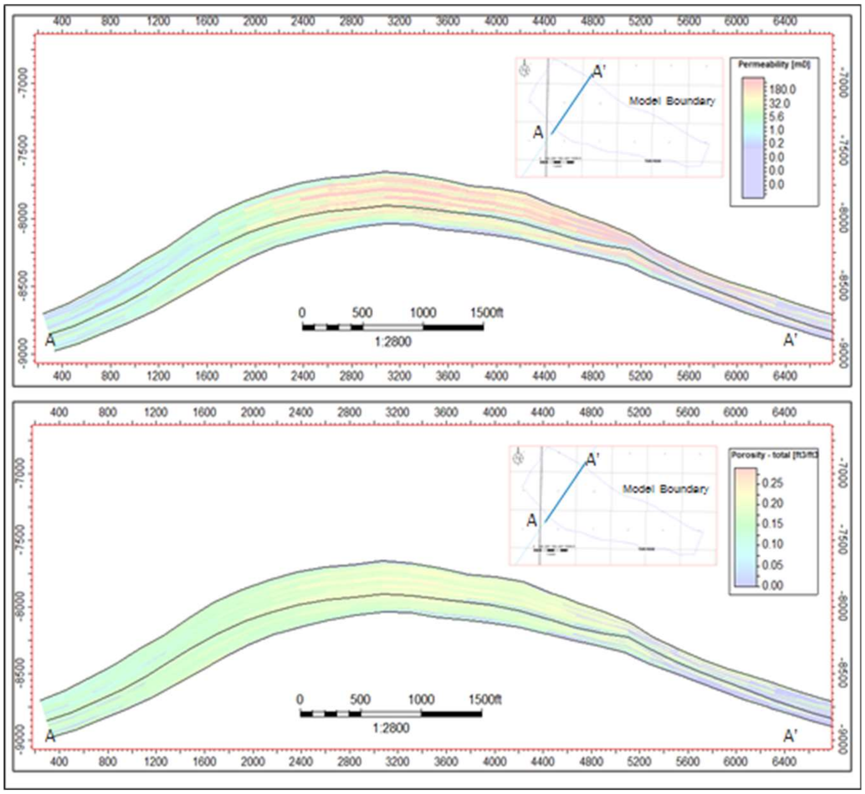


**Figure 2: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.**



**CLASS VI PERMEABILITY DETERMINATION**
**ELK HILLS A1-A2 PROJECT**

## Model Permeability

### *Static Modeling Permeability*

Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Mercury Injection Capillary Pressure (MICP) permeability and porosity data from core analysis constrains the permeability function (Figure 1). Permeability is populated in the static model with the function utilizing the upscaled porosity and clay volume as inputs. Figure 2 shoes the permeability distribution in the model.

**Figure 1: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.**

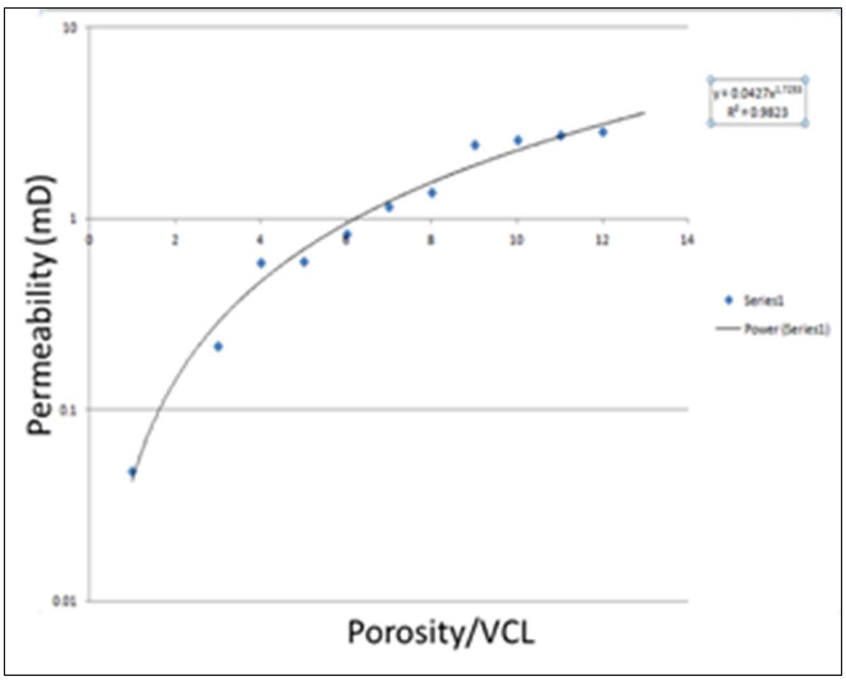
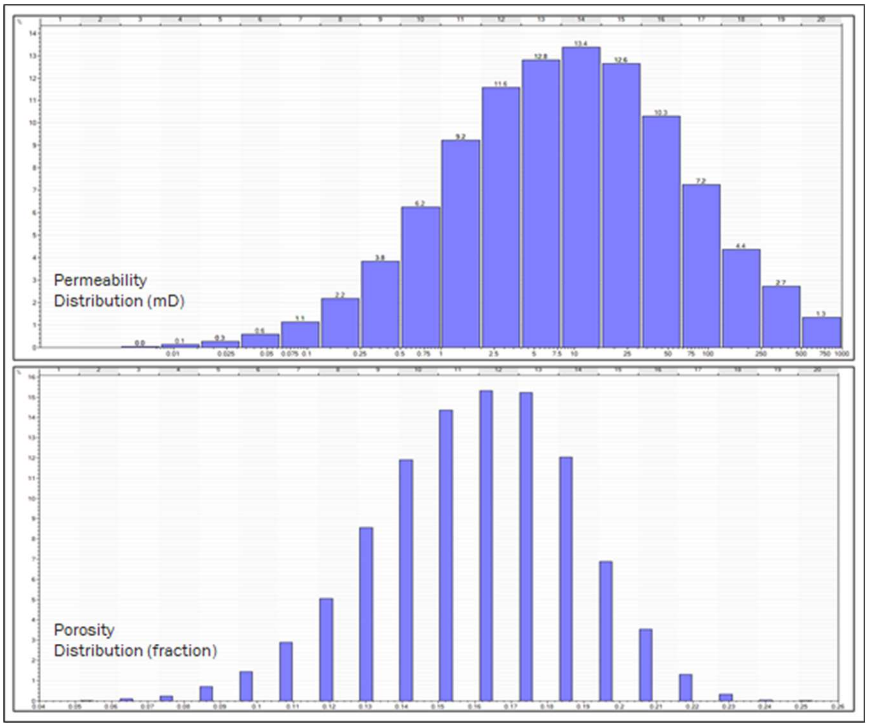


**Figure 2: Monterey Formation A1-A2 sands porosity and permeability distribution in the static model.**



CLASS VI POROSITY IMAGES
ELK HILLS A1-A2 PROJECT

## Porosity Distribution

Figure 1 shows porosity and permeability histograms for the Monterey Formation A1-A2 sands. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 2 shows the permeability and porosity distribution in cross-section A-A'. Reservoir quality is the highest at the top of the anticline, porosity and permeability are lower on the edges.

**Figure 1: Monterey Formation A1-A2 sands porosity and permeability distribution in the static model.**

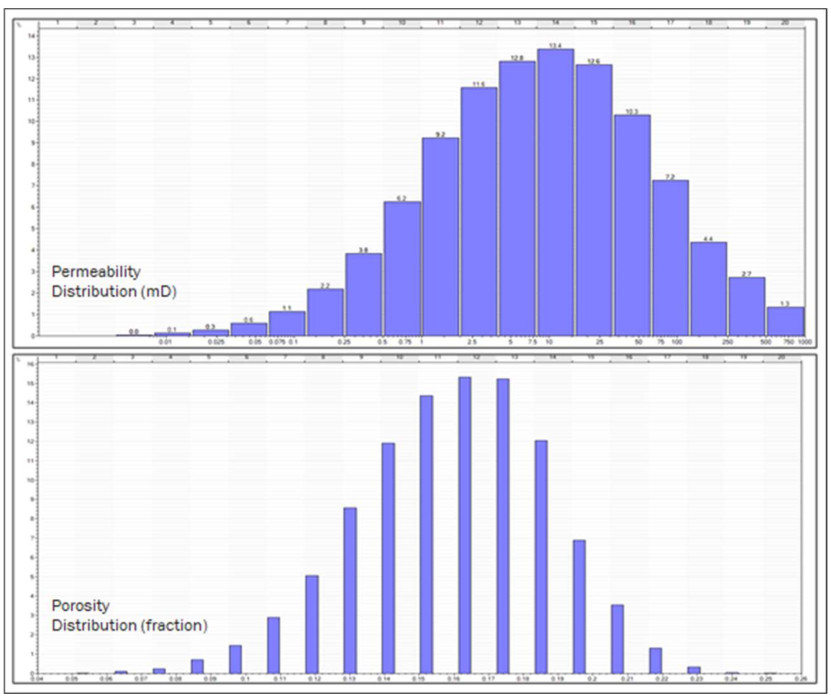
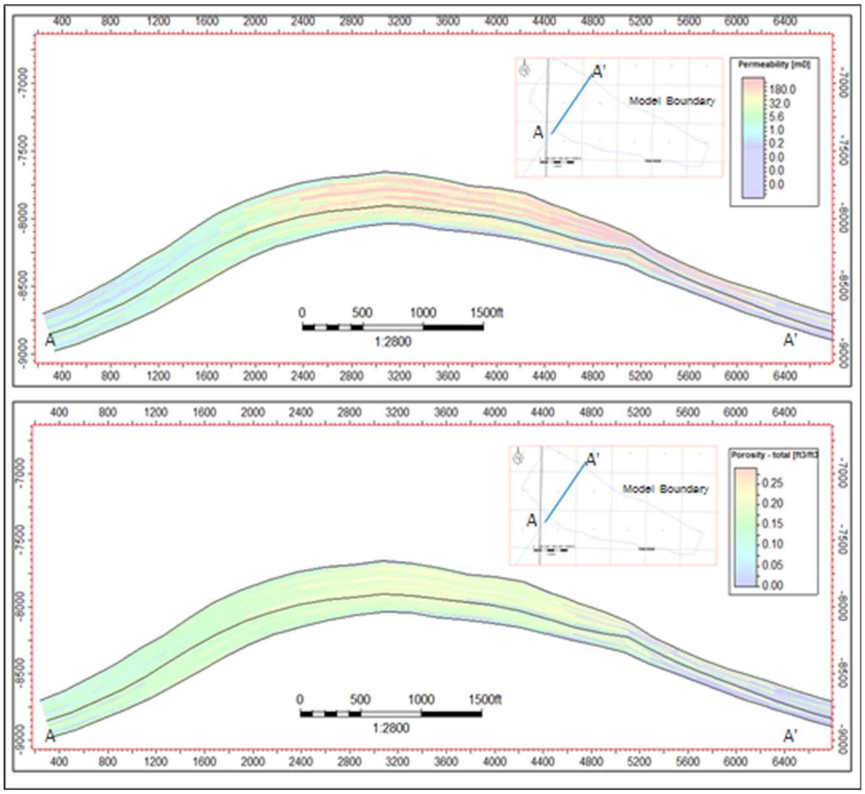


**Figure 2: Sections through the static grid showing the distribution of porosity and permeability in the reservoir.**



**CLASS VI POROSITY DETERMINATION**
**ELK HILLS A1-A2 PROJECT**

## Model Porosity

Porosity, facies (sand and shale), and clay volume are derived from the open hole well logs. These values, that have a one-foot resolution, are upscaled into the geological model and distributed using Gaussian random function simulation (kriging). Mercury Injection Capillary Pressure (MICP) permeability and porosity data from core analysis constrains the permeability function (Figure 1). Permeability is populated in the static model with the function utilizing the upscaled porosity and clay volume as inputs. Figure 2 shoes the permeability distribution in the model.

**Figure 1: Porosity and permeability data from MICP analysis for Monterey Formation sands. A permeability transform calculates permeability from log-based porosity.**

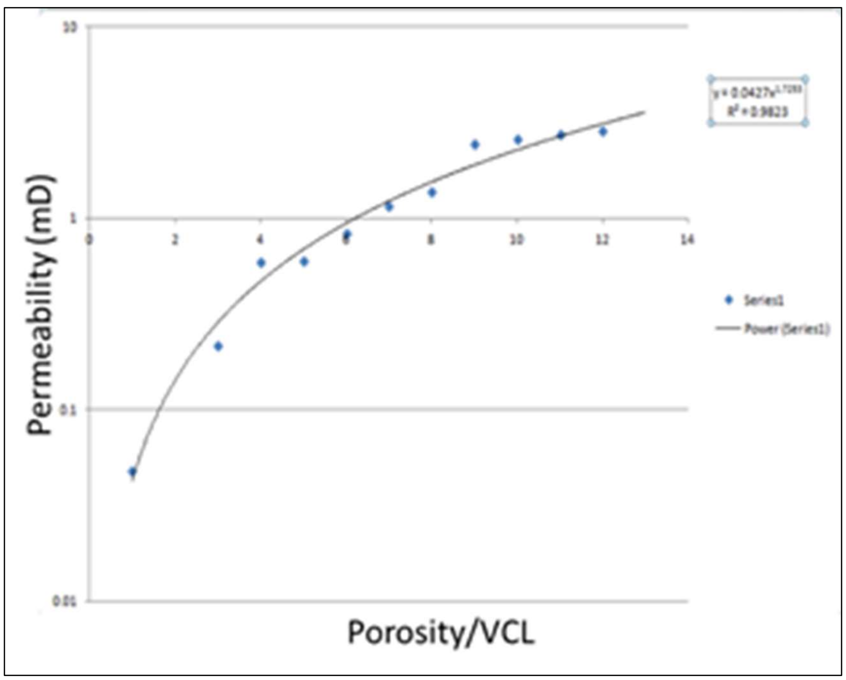
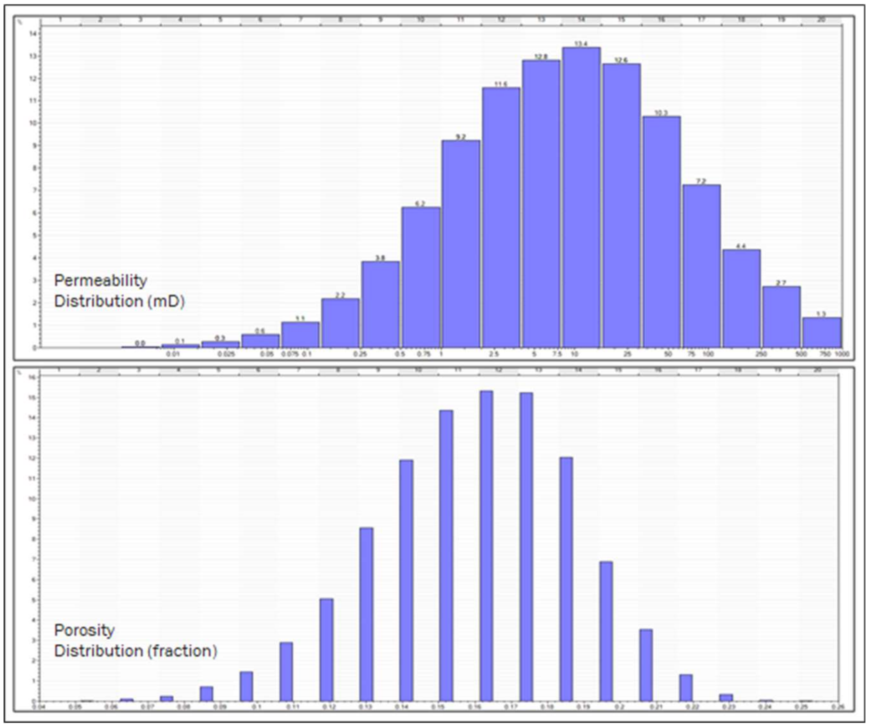


**Figure 2: Monterey Formation A1-A2 sands porosity and permeability distribution in the static model.**



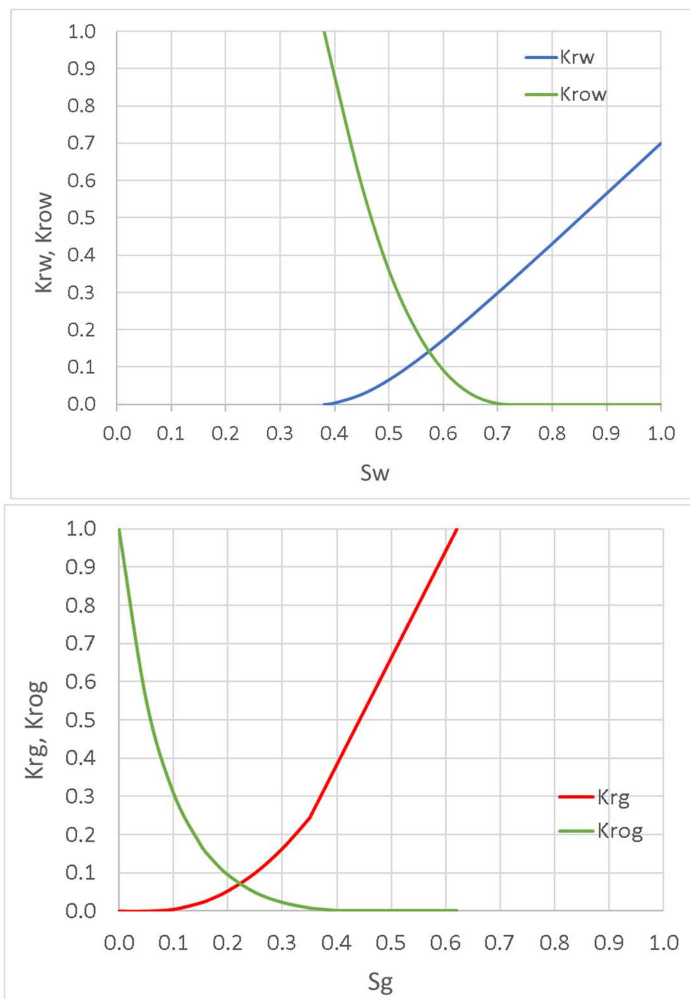
**CLASS VI RELATIVE PERMEABILITY**

**ELK HILLS A1-A2 PROJECT**

## Relative Permeability

With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving Krw, Krow, Krg, and Krog as a function of water or liquid saturation. Data acquired from core flood and/or capillary pressure testing determines these relationships. Figure 1 shows the relative permeability curves used in the computational modeling.

**Figure 1: Relative permeability curves for Krg-Krog and Krw-Krow used in the computational model study.**



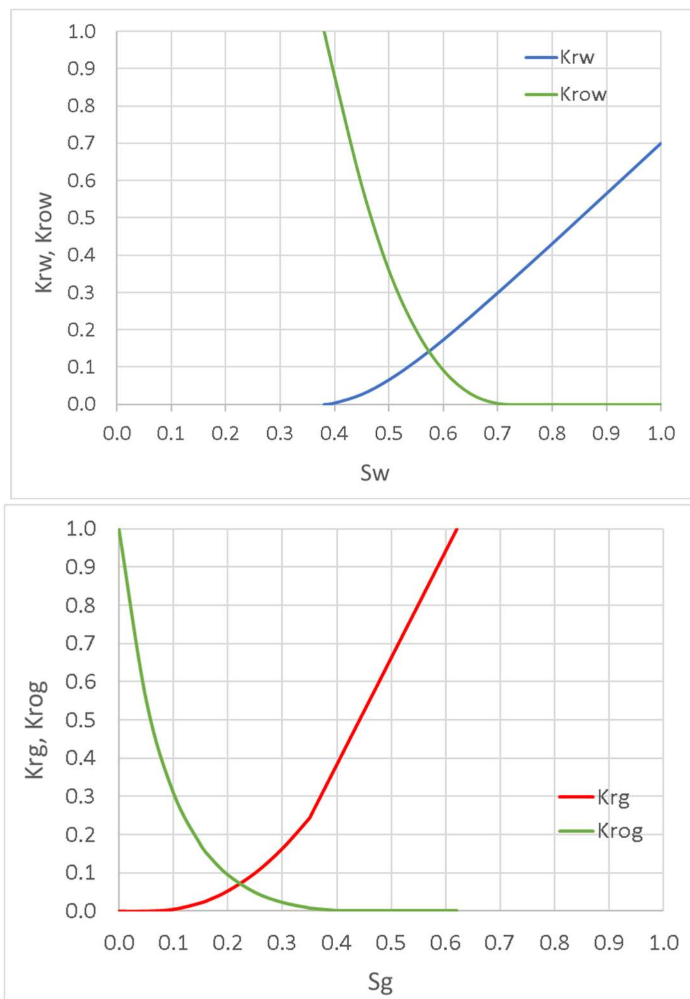
## CLASS VI RELATIVE PERMEABILITY

## ELK HILLS A1-A2 PROJECT

### Relative Permeability

With gas, oil and water all present in the reservoir, three-phase relative permeability relationships are the key variables that determine the flow characteristics of each component and/or phase. Two sets of two-phase relative permeability data are needed to determine three-phase relative permeability: water-oil and gas-oil systems, giving Krw, Krow, Krg, and Krog as a function of water or liquid saturation. Data acquired from core flood and/or capillary pressure testing determines these relationships. Figure 1 shows the relative permeability curves used in the computational modeling.

**Figure 1: Relative permeability curves for Krg-Krog and Krw-Krow used in the computational model study.**



```
<?xml version="1.0" encoding="utf-8" ?>
- <!--
INFO: This file accompanies a data file and contains the spatial context.
  -->
- <!--
INFO: It was made by serializing an Ocean spatial companion information record.
  -->
- <!--
INFO: The coordinate reference system (CRS) is verbosely defined as ESRI well-
  known-text (WKT).
  -->
- <SpatialCompanion version="1.0">
- <IEarlyBoundCoordinateReferenceSystem name="CA83-VF" crsType="Projected"
    engine="ESRI" engineVersion="PE_10_3_1">
  <Description>"MENTOR:CA83-VF:NAD83 California State Planes, Zone V, US
    Foot"</Description>
  <AuthorityCode>SIS,501034</AuthorityCode>
- <ILateBoundCoordinateReferenceSystem
    name="NAD_1983_StatePlane_California_V_FIPS_0405_Feet">
  <AuthorityCode>EPSG,2229</AuthorityCode>
  <WKT>PROJCS["NAD_1983_StatePlane_California_V_FIPS_0405_Feet",GEOGCS["GC
    S_North_American_1983",DATUM["D_North_American_1983",SPHEROID["GRS_1
    980",6378137.0,298.257222101]],PRIMEM["Greenwich",0.0],UNIT["Degree",0.01
    74532925199433]],PROJECTION["Lambert_Conformal_Conic"],PARAMETER["Fals
    e_Easting",6561666.66666667],PARAMETER["False_Northing",1640416.6666666
    7],PARAMETER["Central_Meridian",-
    118.0],PARAMETER["Standard_Parallel_1",34.0333333333333],PARAMETER["Sta
    ndard_Parallel_2",35.4666666666667],PARAMETER["Latitude_Of_Origin",33.5],U
    NIT["Foot_US",0.304800609601219],AUTHORITY["EPSG",2229]]</WKT>
    </ILateBoundCoordinateReferenceSystem>
- <ISimpleTransform>
  <AuthorityCode>EPSG,1188</AuthorityCode>
  <WKT>GEOGTRAN["NAD_1983_To_WGS_1984_1",GEOGCS["GCS_North_American_1
    983",DATUM["D_North_American_1983",SPHEROID["GRS_1980",6378137.0,298.
    257222101]],PRIMEM["Greenwich",0.0],UNIT["Degree",0.0174532925199433]],
    GEOGCS["GCS_WGS_1984",DATUM["D_WGS_1984",SPHEROID["WGS_1984",637
    8137.0,298.257223563]],PRIMEM["Greenwich",0.0],UNIT["Degree",0.017453292
    5199433]],METHOD["Geocentric_Translation"],PARAMETER["X_Axis_Translation"
    ,0.0],PARAMETER["Y_Axis_Translation",0.0],PARAMETER["Z_Axis_Translation",0.
    0],AUTHORITY["EPSG",1188]]</WKT>
    </ISimpleTransform>
    </IEarlyBoundCoordinateReferenceSystem>
- <ExamplePointConversions>
- <ExampleConversion>
  <Point location="6095241.809492 2302015.1459605"
    coordinateReferenceSystemId="CA83-VF" />
  <Point location="-119.563328480463 35.3079350286311"
    coordinateReferenceSystemId="GCS_North_American_1983" />
  <Point location="-119.563328480463 35.3079350277393"
    coordinateReferenceSystemId="GCS_WGS_1984" />
    </ExampleConversion>
```

```
- <ExampleConversion>
  <Point location="6122433.255109 2302015.1459605"
    coordinateReferenceSystemId="CA83-VF" />
  <Point location="-119.472203632373 35.3090630011981"
    coordinateReferenceSystemId="GCS_North_American_1983" />
  <Point location="-119.472203632373 35.3090630003063"
    coordinateReferenceSystemId="GCS_WGS_1984" />
    </ExampleConversion>
- <ExampleConversion>
  <Point location="6122433.255109 2316903.1161845"
    coordinateReferenceSystemId="CA83-VF" />
  <Point location="-119.472934808075 35.3499610286601"
    coordinateReferenceSystemId="GCS_North_American_1983" />
  <Point location="-119.472934808075 35.3499610277685"
    coordinateReferenceSystemId="GCS_WGS_1984" />
    </ExampleConversion>
- <ExampleConversion>
  <Point location="6095241.809492 2316903.1161845"
    coordinateReferenceSystemId="CA83-VF" />
  <Point location="-119.564104899495 35.3488325116957"
    coordinateReferenceSystemId="GCS_North_American_1983" />
  <Point location="-119.564104899495 35.3488325108041"
    coordinateReferenceSystemId="GCS_WGS_1984" />
    </ExampleConversion>
    </ExamplePointConversions>
  <Info history="Made by Petrel" />
    </SpatialCompanion>
```

**CLASS VI SATURATION HEIGHT FUNCTION**

**ELK HILLS A1-A2 PROJECT**

## Saturation Height Function

Initial hydrocarbon saturation is modeled using centrifuge, porous plate, and mercury injection core analysis results. Data from 5 wells was compiled and used to derive a single equation across the range of rock quality sampled. The height function is derived from permeability, which is a function of porosity and clay volume and therefore believed to be the best representation of rock quality. Figure 1 shows saturation versus permeability. Figure 2 shows well 357-7R saturation from the saturation function.

Saturation Height Function = ( 1.48137 - 0.5747 * Log((8860+TVDSS) * 0.06503) - 0.0671 * Log((8860+TVDSS)*0.06503)^2 + 0.0316 * Log((8860+TVDSS) * 0.06503)^3 ) / ( KA^0.17271)

**Figure 1: Plot of saturation versus permeability for various TVDSS depths.**

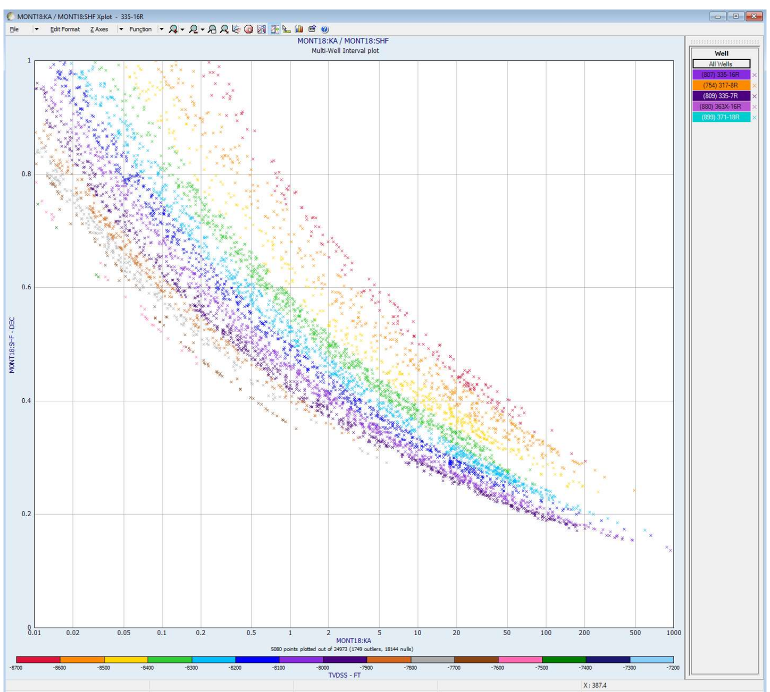
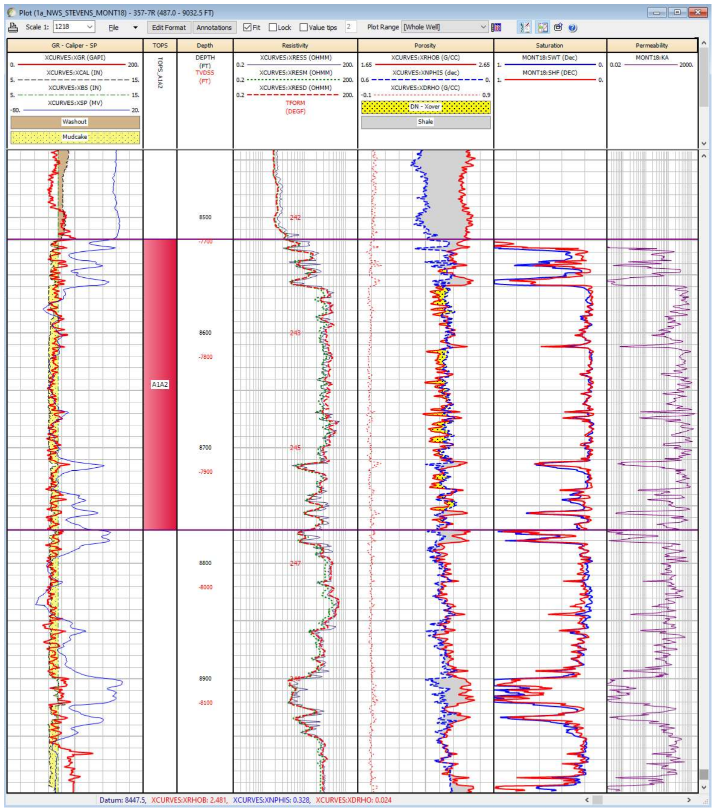


**Figure 2. Example log plot of saturation height function compared to log-derived water saturation for 357-7R.**



***Predictions of System Behavior***

The following maps (Figure 1) and cross-sections (Figure 2) show the computational modeling results and development of the $CO_2$ plume at four –time-steps. For all layers in the model and at all time-steps, the plume stays within the 2.1 square mile AoR. Within the first two years of injection, the AoR extent is largely defined. Thereafter, the $CO_2$ injectate concentration in the plume increases with continued injection. Post-injection the plume does not decrease in size. The majority of the $CO_2$ injectate remains as super-critical $CO_2$. Figure 3 shows pressure 100 years post injection for the op layer of the reservoir.

**Figure 1: Plan view showing the plume development through time for layer 15. Note that the plume does not change from 50 years post injection to 100 years post injection.**

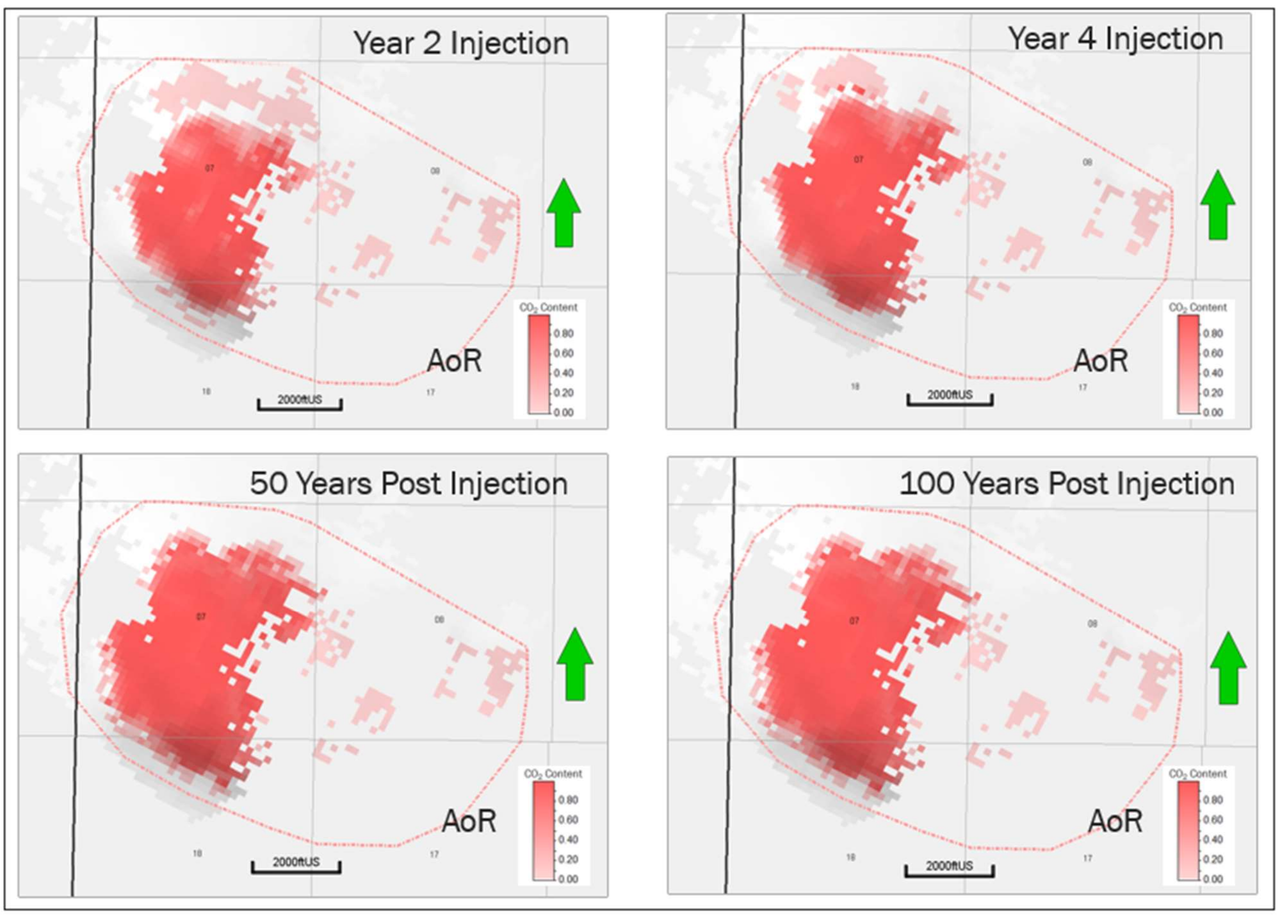


**Figure 2: Cross-sections showing the plume development through varying times through the project. Note that the plume does not change from 50 years post injection to 100 years post injection.**

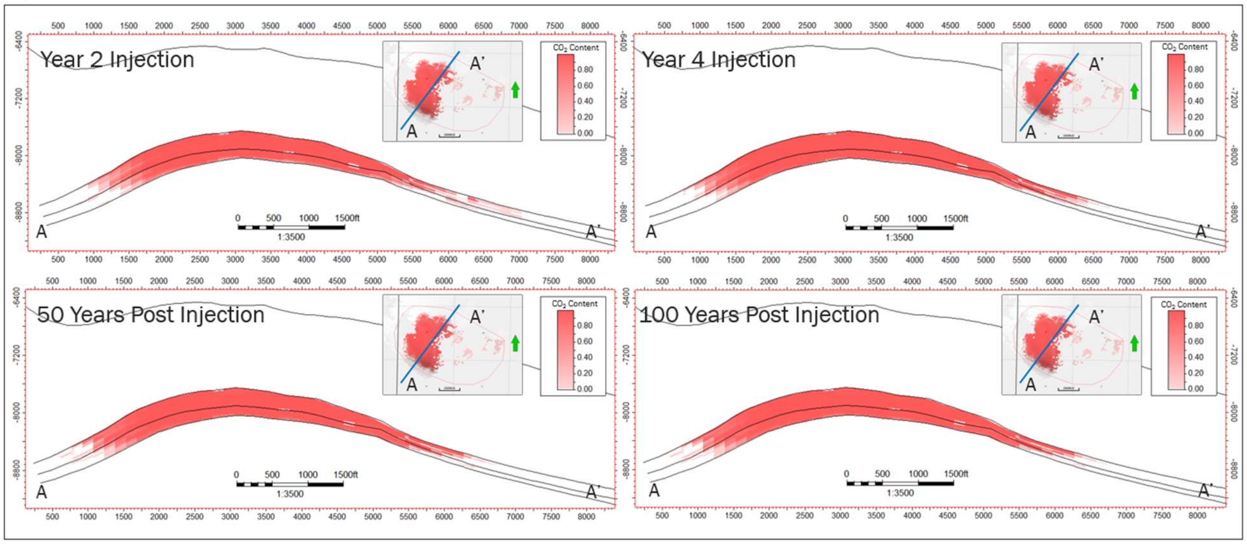
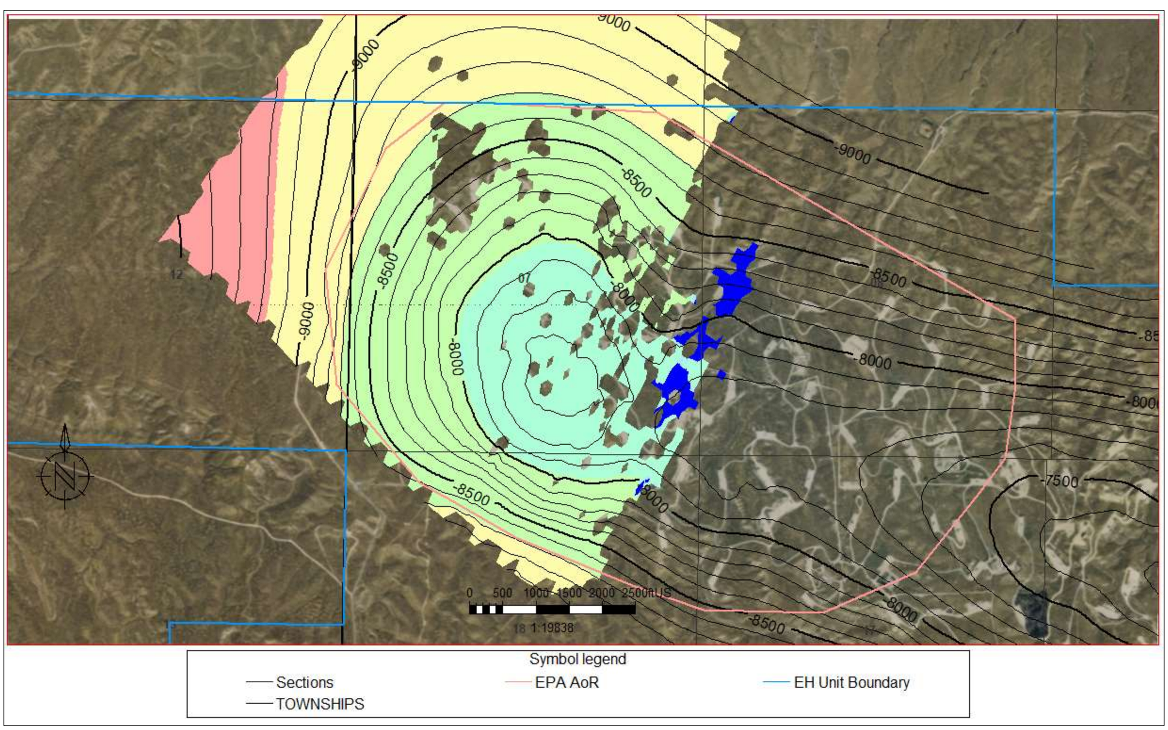



**Figure 3: Pressure post injection for top layer of the computational model.**



## Class VI UIC Financial Responsibility Demonstration

This submission is for:

Project ID: R09-CA-0003

Project Name: CRC CalCapture A1-A2

Current Project Phase: Pre-Injection Prior to Construction

## Cost Estimates

Company providing estimates: EPA - Cost Estimation Tool with Inflation

Cost of each phase: Date of Third-Party Estimate:

Corrective Action on Deficient Wells: $0.00 1/1/2021

Plugging Injection Well: $193,669.00 1/1/2021

Post-Injection Site Care and Site Closure: $22,760,143.00 1/1/2021

Emergency and Remedial Response: $27,299,183.00 1/1/2021

Total Cost Estimate: $50,252,995.00

Year of Dollars: 2021

Cost Estimate File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/FinancialResp-08-02-2021-1949/FR--Cost--Estimation--2021.xlsx

Additional Cost Information: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/FinancialResp-08-02-2021-1949/Financial--Responsibility--Cost--Estimates--Description.pdf

## Trust Fund

## Surety Bond

## Letter of Credit

Number of Letter of Credit Instruments: 1

### Letter of Credit #1

Proof of Third Party Financial Strength

Using credit ratings to prove financial strength: Yes

Name of Issuing Institution: California Resources Corporation

Credit Rating: B1 (Stable)

Rating Date: 12/1/2020

Company Issuing Rating: Moody's

Phases Covered by Instrument:

Corrective Action on Deficient Wells

Plugging Injection Well

Post-Injection Site Care and Site Closure

Total Cost of Selected Phases: $22,953,812.00

Using more than one instrument to cover a single phase: No

Value of Instrument: $23,147,481.00

Instrument Language

Standby Trust

Has a standby trust been established: No

Instrument File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/FinancialResp-08-02-2021-1949/Financial--Responsibility--Letter--of--Credit.pdf

## Third Party Insurance

Number of Third Party Insurance Instruments: 1

### Third Party Insurance #1

Proof of Third Party Financial Strength

Using credit ratings to prove financial strength: Yes

Name of Issuing Institution: California Resoureces Corporation

Credit Rating: B1 (Stable)

Rating Date: 12/1/2020

Company Issuing Rating: Moody's

Describe: Policy will be active prior to the commencement of injection.

Describe: Policy will expire after injection cease.

Phases Covered by Instrument:

Emergency and Remedial Response

Total Cost of Selected Phases: $27,299,183.00

Using more than one instrument to cover a single phase: No

Value of Instrument: $27,299,183.00

Instrument Language

Instrument File: https://epa.velo.pnnl.gov/alfresco/service/velo/getFile/no_wiki/shared/Submissions/R09-CA-0003/Phase1-PreConstruction/FinancialResp-08-02-2021-1949/Financial--Responsibility--Insurance--Description.pdf

## Escrow Account

## Self Insurance

Is Self Insurance Used as a Financial Instrument: No

## Other Instrument

## Notifications

## Complete Submission

Authorized submission made by: Travis Hurst

For confirmation a read-only copy of your submission will be emailed to: travis.hurst@crc.com

# CLASS VI FINANCIAL RESPONSIBILITY DEMONSTRATION

## COST ESTIMATES DESCRIPTION
## 40 CFR 146.85

## Elk Hills A1-A2 Storage Project

### Description of Financial Responsibility Cost Estimates

Carbon TerraVault 1 LLC (CTV) utilized the EPA Cost Estimation Tool for Class VI Financial Responsibility Demonstration. The 2015 estimates provided by the EPA have been updated by CTV with an annual inflation rate of 2.5%.

Prior to injection and project approval CTV will provide updated estimates that are verified with a third party contractor.

Financial responsibility will be covered by the following:

1. **Letter of Credit** for Post-Injection Site Care and Closure and Injection Well Plugging.

2. **Insurance** coverage for Emergency and Remedial Response.

# FINANCIAL RESPONSIBILITY

## CLASS VI EMERGENCY AND REMEDIAL RESPONSE INSUREANCE
## 40 CFR 146.85

## Elk Hills A1-A2 Storage Project

### Emergency and Remedial Response Insurance

Carbon TerraVault 1 LLC (CTV) will provide financial assurance for **Emergency and Remedial Response** by procuring an environmental insurance policy. The limits will be determined by a reasonable estimate of the cost of these activities prior to the commencement of injection operations. The Elk Hills A1-A2 project environmental insurance policy will be placed with an A.M. Best A or higher rated carrier and will cover all emergency and remedial response activities arising from the assets. The selected insurance carrier will issue a financial assurance certificate in compliance with state and federal regulations.

**FINANCIAL RESPONSIBILITY**

**CLASS VI INJECTION WELL PLUGGING AND POST-INJECTION SITE CARE AND CLOSURE LETTER OF CREDIT**
**40 CFR 146.85**

**Elk Hills A1-A2 Storage Project**

## Letter of Credit Description

Carbon TerraVault 1 LLC (CTV) will provide financial assurance for Injection Well Plugging and Post-injection Site Care and Site Closure by posting a letter of credit. The amount of each letter of credit would be determined by a reasonable estimate of the cost of these activities. At this time, the combined value of these two activities is approximately $22 million. CTV will provide an updated estimate from a third party prior to project approval.

The letter of credit will be backed by California Resources Corporation's (CRC) Credit Agreement with Citibank, N.A., as administrative agent, and certain other lenders as participants. This credit agreement consists of a senior revolving loan facility (Revolving Credit Facility) with an aggregate commitment of $492 million, which CRC is permitted to increase if CRC obtains additional commitments from new or existing lenders. The Revolving Credit Facility also includes a sub-limit of $200 million for the issuance of letters of credit. The letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters.

As of June 30, 2021, CRC had an undrawn Revolving Credit Facility, approximately $75 million available in letter of credit issuance capacity and $151 million of cash. CRC is currently making efforts to add to the aggregate commitment and the sub-limit for letters of credit.

## About EPA's Cost Estimation Tool for Class VI Financial Responsibility Demonstrations

This Cost Tool is designed to provide an "acceptable range of costs" for activities for which financial responsibility is required at 40 CFR 146.85(a)(2). Based on information submitted with a Class VI permit application, it generates cost estimates for performing corrective action, injection well plugging, post-

### Using the Cost Tool

The Cost Tool includes tabs for (1) project-specific inputs provided by the user and (2) outputs of the generated cost estimates. There are also two hidden tabs in which the cost estimations and

### The Inputs Tab

The information entered on this tab should be based on the permit application and revised as

**Contact information** – in the first section of the tab, enter the name and address/location of the project and a name/contact information for the applicant. This information does not affect the cost

**Project information** – enter the surface area of the AoR, whether any underground sources of drinking water (USDWs) are present, the mass of $CO_2$ to be injected, the PISC timeframe, and the depth and

**Monitoring wells** – enter the total number of monitoring wells associated with the project in cell B22. Include the name, depth (in feet), and diameter (in inches) of all monitoring wells on rows 24, 25, and

**Corrective action** – if any wells in the AoR require corrective action that will not be complete when the permit is issued, enter the total number of deficient wells in cell B29. Enter the name, depth (in feet),

### The Outputs Tab

Based on the information entered, the Cost Tool generates a table presenting low, medium, and high cost estimates for each activity for which financial responsibility is required. Note that these outputs

It is important to note that the Cost Tool outputs are intended to be estimates only. The specific activities described in the Cost Tool may not match the activities planned by the applicant and the unit cost for specific activities may differ. However, the range of cost estimates generated can help identify

**Corrective action** – this cost estimate depends primarily on the number of wells that are deficient and

**Well plugging** – some elements of this cost estimate depend on the depth and diameter of the

**PISC** – the cost estimates for this activity assume that the permit applicant will conduct groundwater monitoring and perform seismic surveys for the duration of the PISC timeframe. The cost estimate is

**Site closure** – this estimate is based on the number, depth, and diameter of the monitoring wells that will need to be plugged. It also estimates costs for site remediation, which are independent of the

**Emergency and remedial response** – this estimate and the activities that are anticipated to occur are based on the presence/absence of a USDW in the AoR that could be contaminated. If there is no USDW present, the tool assumes a response scenario that involves remediating the injection well, i.e., ceasing injection, repairing the well and replacing the tubing, and creating a hydraulic barrier to stop

### Providing Feedback/Other Sources of Information

If you have any questions about using the Cost Tool or interpreting the results, or if you would like to

Note that evaluating cost estimates is only part of the financial responsibility evaluation. The EPA has also developed a set of electronic checklists to support the evaluation of proposed financial responsibility instruments. For additional information on evaluating financial responsibility, including

All of the reference materials noted above are available in the resource library of the GSDT.

**References:**

American Petroleum Institute (API). 2010. *2008 Joint Association Survey on Drilling Costs* . Washington, DC.
Bureau of Labor Statistics (BLS). 2011. "May 2010 National Occupational Employment and Wage Estimates
Bureau of Labor Statistics (BLS). Undated. "Employment Cost Index: Historical Listing." Bureau of Labor Statistics.
Department of Energy (DOE). 2001. *Pump Life Cycle Costs: A Guide to LCC Analysis for Pumping Systems* . Office
Edmonton Utility Board. 2005. *Directive 011: Licensee Liability Rating (LLR) Program Updated Industry Parameters and*
EduMine - Professional Development and Training for Mining and the Geosciences (EduMine). undated.
Energy Information Administration (EIA). 2010. "Oil and Gas Lease Equipment and Operating Costs 1994 Through
Engineering News-Record (ENR). 2012. "Building Cost Index History as of May 2012." Engineering News-Record.
Enilari, M. 2005. Development and Evaluation of Various Drilling Fluids for Slim Hole Wells. Master's Thesis,
Internal Revenue Service (IRS). 2012. "Yearly Average Currency Exchange Rates." Small Business and Self-
King, George E. 2009. "Brines and Other Workover Fluids." George E. King Engineering. Accessed 6/20/2012.
Nebraska Energy Statistics. 2012. "Annual Average Price per Kilowatthour by State (Lowest to Highest Rate as of
Petroleum Services Association of Canada (PSAC). 2008. 2008 Well Cost Study Summer Costs.
R. Nygaard and R. Lavoie. 2009. "Project Cost Estimate: Wabamun Area CO2 Sequestration Project (WASP)."
Reynolds, Rodney and Robert D. Kiker. 2003. *Produced Water and Associated Issues: A Manual for the*
The Society of Petroleum Engineers (SPE). 2010. *Annual Membership Salary Survey Highlight Report* . Richardson,
U.S. Environmental Protection Agency (EPA), Office of Drinking Water. 1983. *Technical Manual Injection Well*
U.S. Environmental Protection Agency (EPA), Office of Solid Waste and Emergency Response. 2001a. *Cost Analyses for Selected Groundwater Cleanup Projects: Pump and Treat Systems and Permeable Reactive Barriers* .
U.S. Environmental Protection Agency (EPA), Office of Solid Waste and Emergency Response. 2001b. *Groundwater Pump and Treat Systems: Summary of Selected Cost and Performance Information at Superfund-*
World Resources Institute (WRI). 2008. *CCS Guidelines: Guidelines for Carbon Dioxide Capture, Transport, and*

**IInstructions: Please fill out the green highlighted cells below with project -specific information from the Class VI permit application.**

**Project Information**

| Variable Name | Value |
|---|---|
| Project Name (Corporate entity) | CRC |
| Project Address/Location | 28590 Highway 119 Tupman CA 93276 |
| Contact Name | Travis Hurst |
| Contact Information for Project Operator | travis.hurst@crc.com 661-342-2409 |

**Project Data**

| Variable Name | Value | Units (Click in Cell for Dropdown List) |
|---|---|---|
| Size of Area of Review (AoR) | 2.1 | Square Miles |
| Are There Underground Sources of Drinking Water (USDWs) in the AoR? | No | |
| Mass of $CO_2$ to be Injected | 8,000,000 | Metric Tons |
| Duration of Post-Injection Site Care | 50 | Years |
| Depth of Injection Well | 8,900 | Feet |
| Diameter of Injection Well | 7.0 | inches |

←If there are no USDWs, but there are other (non-USDW) types of groundwater in the operator would be required to remediate (if contaminated by a well failure), select 'Yes

**Information on Monitoring Wells** *Note: Cost to clean out monitoring wells is based on a regression equation that is only valid for well depths greater than 2,000 ft. Model is run for all monitoring wells (whe wells are conservatively assumed to be 2,001 ft deep).*

4 ←Number of Monitoring Wells

Enter the names, depths (feet), and diameters (inches) of monitoring wells in the table below.

| Well Name | Monterey FM | Tulare USDW | Monterey FM | Etchegoin | | [Well Name] | [Well Name] | [Well Name] | [Well Name] | [Well Name] | [Well Name] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Well Depth (feet) | 9,900 | 2,500 | 9,900 | 5,000 | | | | | | | |
| Well Diameter (inches) | 7.0 | 16 | 7 | 7 | | | | | | | |

**Information on Deficient Wells in the AoR Requiring Corrective Action**

0 ←Number of Deficient Wells in the AoR that will be Remediated

Enter in the names, depths (feet), and diameters (inches) of deficient wells in the aor requiring corrective action in the table below.

| Well Name | [Well Name] | [Well Name] | [Well Name] | [Well Name] | [Well Name] | [Well Name] | [Well Name] | [Well Name] | [Well Name] | [Well Name] | [Well Name] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Well Depth (feet) | | | | | | | | | | | |
| Well Diameter (inches) | | | | | | | | | | | |

e AoR that the
s'.

re the shallow

| |
|---|
| [Well Name] |
| |
| |

| |
|---|
| |
| |
| |

## Amount Needed to Show Financial Responsibility (2015$)

| Project Task | Low End Cost Estimate ($/Project; includes 20% G&A) | Middle Cost Estimate ($/Project; includes 20% G&A) | High End Cost Estimate ($/Project; includes 20% G&A) |
|---|---|---|---|
| **Performing Corrective Action on Deficient Well(s) in AoR** | | | |
| Maintenance Rig Rental (Clean Out Deficient Wells) | $ - | $ - | $ - |
| Flush Deficient Wells | $ - | $ - | $ - |
| Plug Deficient Wells | $ - | $ - | $ - |
| Log Deficient Wells | $ - | $ - | $ - |
| **Subtotal: Corrective Action Cost** | **$ -** | **$ -** | **$ -** |
| **Plugging Injection Well** | | | |
| Maintenance Rig Rental (Clean Out Injection Well) | $ 41,000 | $ 89,000 | $ 101,000 |
| Perform Mechanical Integrity Test Before Plugging Injection Well | $ 52,000 | $ 52,000 | $ 52,000 |
| Flush Injection Well with a Buffer Fluid Before Plugging | $ 200 | $ 1,700 | $ 5,000 |
| Plug Injection Well | $ 15,000 | $ 20,000 | $ 91,000 |
| Log Injection Well | $ 4,000 | $ 4,000 | $ 18,000 |
| **Subtotal: Injection Well Plugging Cost** | **$ 128,726** | **$ 193,669** | **$ 309,638** |
| **Post-Injection Site Care (assume 0% discount rate)** | | | |
| Post-Injection O&M for Monitoring Wells<br>Post-Injection Seismic Survey<br>Post-Injection Groundwater Monitoring<br>Post-Injection Monitoring Reports to Regulators | **$ 16,337,761** | **$ 22,760,143** | **$ 29,362,278** |
| **Site Closure** | | | |
| Maintenance Rig Rental (Clean Out Monitoring Wells) | $ 89,000 | $ 195,000 | $ 222,000 |
| Perform MIT Before Plugging Monitoring Wells | $ 161,000 | $ 161,000 | $ 161,000 |
| Flush Monitoring Wells | $ 2,000 | $ 14,000 | $ 37,000 |
| Plug Monitoring Wells (occurs at end of PISC; use 0% discounting) | $ 62,000 | $ 81,000 | $ 369,000 |
| Log Monitoring Wells (occurs at end of PISC; use 0% discounting) | $ 14,000 | $ 18,000 | $ 72,000 |
| Remove Injection Well Surface Equipment and Restore Vegetation at Injection Well | $ 19,000 | $ 35,000 | $ 50,000 |
| Remove Monitoring Well Surface Equipment and Restore Vegetation (occurs at end of PISC; use 0% discounting) | $ 78,000 | $ 138,000 | $ 199,000 |
| Document Plugging and Site Closure Process | $ 19,000 | $ 19,000 | $ 19,000 |
| **Subtotal: Site Closure Cost** | **$ 514,904** | **$ 767,717** | **$ 1,309,294** |
| **Emergency and Remedial Response, Scenario A: Remediate Leaking Injection Well** | | | |
| Stop CO2 Injection | $ 1,000 | $ 1,000 | $ 3,000 |
| Repair Injection Well | $ 16,000 | $ 35,000 | $ 40,000 |
| Replace Tubing | $ 133,000 | $ 133,000 | $ 133,000 |
| Create Hydraulic Barrier | $ 8,009,000 | $ 9,096,000 | $ 13,911,000 |
| **Subtotal: Scenario A** | **$ 8,159,000** | **$ 10,744,560** | **$ 14,087,000** |
| **Total Amount Needed to Show Financial Responsibility** | **$ 26,444,489** | **$ 34,466,088** | **$ 47,317,811** |

Note: Results may not add due to independent rounding.